AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

2022 Integrated System Plan

June 2022

For the National Electricity Market

Important notice

Purpose

AEMO publishes the 2022 Integrated System Plan (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 supporting functions under the National Electricity Rules.

This publication has been prepared by AEMO using information available at 15 October 2021 (for Draft 2022 ISP modelling) and 19 May 2022 (for 2022 ISP modelling). AEMO has acknowledged throughout the document where modelling has been updated to reflect the latest inputs and assumptions. Information made available after these dates has been included in this publication where practical.

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Version control

Version	Release date	Changes
1.0	30/6/2022	Initial release.

AEMO acknowledges the Traditional Owners of country throughout Australia and recognises their continuing connection to land, waters and culture. We pay respect to Elders past and present.

The NEM integrated system plan

The 2022 *Integrated System Plan* (ISP) comes at a time when the future of Australia's energy is a matter of great national urgency.

As it has since 2018, the ISP offers the most robust 'whole of system plan' available for supplying affordable and reliable electricity to homes and businesses in the eastern and south eastern states, while supporting Australia's net zero ambitions. From 2025, there will be moments when the National Electricity Market (NEM) has enough renewable energy to meet 100% of that demand.

This plan is for a true transformation of the NEM, from fossil fuels to firmed renewables. It calls for levels of investment in generation, storage, transmission and system services that exceed all previous efforts combined. It cannot offer quick fixes, but it does offer a clear and transparent roadmap through to 2030, and then to 2040 and 2050.

Equally, the ISP calls for Australian industry and communities to be engaged in, help problem-solve, and ultimately support and benefit from that investment. The NEM is capable of delivering enough low-emission electricity to support the nation's most ambitious economic and environmental goals, but it does need a clear social licence for the scale of investment needed.

The 2022 ISP has been developed with involvement from over 1,500 NEM stakeholders through 31 forums and webinars, 198 written submissions, and continuous dialogue on every aspect. The exhaustive consultation, including feedback on the Draft ISP, has been instrumental in both confirming the ISP's direction, and testing its rigour. That rigour has stood up to market events over the past six months.

A clear message from our stakeholders and recent market events is that our energy system transformation is accelerating and irreversible. Recent international events and Australian market events have further strengthened the case for the shift to renewables, and the ISP sets out a roadmap for the NEM that continues to prove itself against these realities. Investment in low-cost renewable energy, firming resources and essential transmission remains the best strategy to deliver affordable and reliable energy, protected against international market shocks. The NEM state government energy policies have long supported this investment, and the Commonwealth Government's Rewiring the Nation policy will support the ISP roadmap's timely and effective delivery.

AEMO thanks the Commonwealth and NEM state governments for the generous and rigorous input they have provided, the Australian Energy Regulator (AER) Board and staff for their input and advice whenever requested, the Transmission Network Service Providers (TNSPs) for their joint planning, and the ISP Consumer Panel for their guidance on both content and stakeholder engagement.

Finally, the Board and I thank AEMO's own people for their immense efforts in delivering the ISP. Our forecasting, system planning, legal, regulatory and engagement teams have worked with precision, expertise and dedication.

Daniel Westerman
Chief Executive Officer

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Abbreviations

AC	alternating current	**NSCAS**	network support and control ancillary services
AEMC	Australian Energy Market Commission	**NSG**	non-scheduled generation
AER	Australian Energy Regulator	**NSP**	network service provider
ARENA	Australian Renewable Energy Agency	**ODP**	optimal development path
CCS	carbon capture and storage	**OWZ**	offshore wind zone
CDP	candidate development path	**PACR**	Project Assessment Conclusions Report
DER	distributed energy resources	**PADR**	Project Assessment Draft Report
DNSP	distribution network service provider	**PEC**	Project EnergyConnect
DSP	demand-side participation	**PFR**	primary frequency response
ESB	Energy Security Board	**PV**	photovoltaic
EV	electric vehicle	**QNI**	Queensland – New South Wales Interconnector
FCAS	frequency control ancillary services	**RET**	Renewable Energy Target
FFR	fast frequency response	**REZ**	renewable energy zone
FOM	fixed operating and maintenance	**RIT-T**	Regulatory Investment Test for Transmission
GW	gigawatt/s	**SIPS**	System Integrity Protection Scheme
HVDC	high voltage direct current	**TNSP**	transmission network service provider
IASR	*Inputs, Assumptions and Scenarios Report*	**TRET**	Tasmanian Renewable Energy Target
IBR	Inverter-based resources	**TWh**	terawatt hour/s
IIO	Infrastructure Investment Opportunities	**V2G**	Vehicle-to-grid
ISP	*Integrated System Plan*	**VOM**	variable operating and maintenance
kW	kilowatt/s	**VNI**	Victoria – New South Wales Interconnector
MW	megawatt/s	**VPP**	virtual power plant
NEM	National Electricity Market	**VRE**	variable renewable energy (at utility scale)
NER	National Electricity Rules		

Executive summary

The irreversible energy transition is a challenge and an opportunity

The National Electricity Market (NEM) is supporting a once-in-a-century transformation in the way electricity is generated and consumed in eastern and south-eastern Australia. It will replace legacy assets with low-cost renewables, add energy storage and other new forms of firming capacity, and reconfigure the grid to support two-way energy flow. Consumers will be able to draw on low-emission electricity for their transport, industry, office and homes, replacing oil, gas and other fuels.

Technical innovation, ageing generation plants, economics, government policies, energy security and consumer choice are all driving this transformation, and driving it faster than many anticipated. Some of them form part of the global push for net zero emissions by 2050, while others are independent. All the while, the NEM must continue to meet its objective – to provide reliable, secure and affordable electricity to consumers.

As the global economy gathers pace towards its net zero future, countries that have excess low-cost renewable energy will be at a distinct advantage. Australia is extremely well-positioned to be one of those countries, with options to export that energy, or use it in industrial production or for energy-intensive digital industries.

The ISP has proven robust to market events through two years of engagement

AEMO, energy consumers, sector representatives, law-makers and policy-makers and other stakeholders have been engaging on these challenges and opportunities since the 2020 ISP. The Draft 2022 ISP was published in December 2021, receiving broad endorsement along with valuable suggestions for input assumptions and other improvements. It considered four scenarios for the pace of energy transformation on the path to reach net zero by 2050. Stakeholders identified the most likely to be the relatively fast *Step Change* scenario, with renewables generating 83% of NEM energy by 2030-31.

Since then, momentum towards decarbonisation has accelerated, confirming the *Step Change* scenario as a solid foundation for planning NEM investment.

Some coal-fired power stations have brought forward their planned exits, offshore wind generation has gained more support, and investors have focused even more on climate and environmental, social, and governance considerations. The NEM state governments have sharpened their policies on energy, electric vehicle, renewables and emissions abatement, shifting to an electrification of the economy supported by firmed renewable energy.

On the other hand, supply chain limitations and other factors are threatening the planned delivery timelines of some transmission projects and have resulted in confirmed or potential changes to timing.

The Commonwealth Government intends to enable and support delivery of transmission investment needed for this transition with its Rewiring the Nation policy. Governments could further support the transition through a range of potential mechanisms such as changes to the regulatory framework, financial mechanisms to better align benefits with costs and the timing of their imposition, and improved recognition of the impact on landholders and communities hosting the required infrastructure.

AEMO has finalised this 2022 ISP after considering and responding to these events and to feedback on the Draft ISP. If there is an over-riding message from both, it is that our energy system transformation is accelerating and irreversible, and ever more comprehensive and challenging. The recent global disruption of international energy markets and supply chains has resulted in high fuel prices domestically, leading to price caps in the gas and electricity spot markets which, when combined with unseasonable high demand, generation plant outages and physical fuel scarcity, led to an unprecedented level of market intervention by AEMO, ultimately necessitating a temporary suspension of the electricity spot market in all regions of the NEM.

These events only confirm energy security as a driver of the transformation, and the potential for firmed renewables to protect consumers from global commodity shocks. Given the breadth of scenarios and range of inputs considered as part of the 2022 ISP, the Optimal Development Path (ODP) remains resilient to these events.

The 2022 ISP is a comprehensive roadmap for the NEM

The 2022 ISP and its optimal development path support Australia's complex and rapid energy transformation towards net zero emissions, enabling low-cost firmed renewable energy and essential transmission to provide consumers in the NEM with reliable, secure and affordable power.

The ISP's optimal development path recognises and guides the significant investment needed in the physical infrastructure and intellectual capital of the NEM. That investment is needed to:

- Meet significantly increased demand as homes, vehicles and industrial applications switch to electricity from existing energy sources. Without coal, this will require a nine-fold increase in utility-scale variable renewable energy (VRE) capacity, and a near five-fold increase in distributed solar photovoltaics (PV),
- Treble the firming capacity from alternative sources to coal that can respond to a dispatch signal, including utility-scale batteries, hydro storage, gas-fired generation, and smart behind-the-meter "virtual power plants" (VPPs),
- Adapt complex networks and markets for two-way electricity flow, while leveraging AEMO's Engineering Framework to prepare the power system for 100% instantaneous penetration of renewables, and
- Efficiently install more than 10,000 km of new transmission, to connect geographically and technologically diverse, low-cost generation and firming with the consumers who rely on it, on a pathway that is low cost and low regrets for consumers, with project work commencing on their earliest planned schedule.

Equally, the ISP recognises and calls for significant investment in the human and social capital needed to deliver the intended consumer benefits and secure the NEM's future:

- Manage the complex and growing supply chain risks that are inherent for investments of this scale that face prior competing claims on plant, skills and resources,
- Engage with landholders and regional communities to co-design solutions that will earn a lasting social licence, and
- Continue with the significant, concurrent and accelerated collaboration between the energy sector and its regulators, governments and communities.

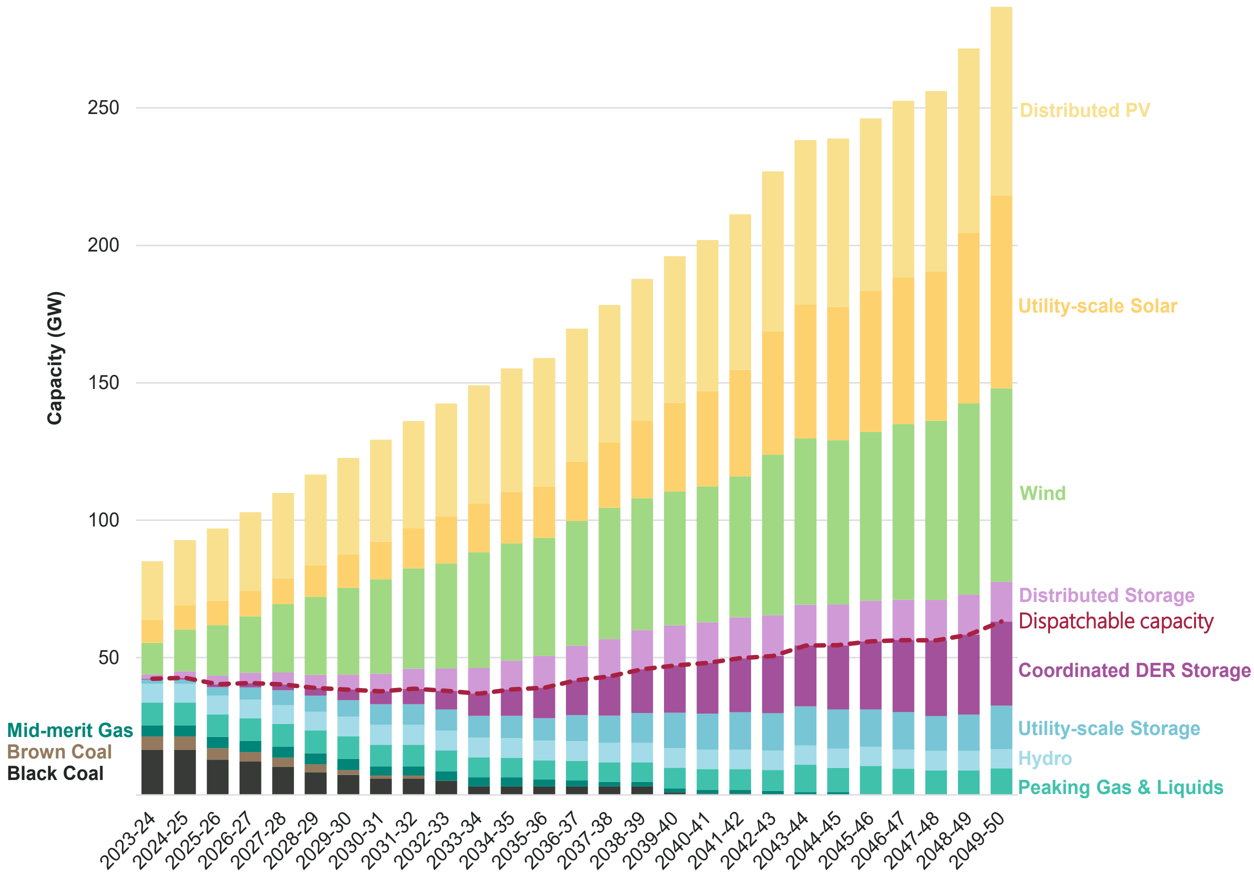
When successful, the transformation of the NEM will deliver low-cost renewable electricity with reliability and security, help meet regional and national climate targets, and contribute significantly to regional jobs and economic growth.

A double transformation: electrification of the economy while switching to firmed renewables

Figure 1 shows the transformation of the NEM's energy mix through the *Step Change* scenario through to 2050. The ISP calls for development opportunities in the Optimal Development Path (the ODP) that would assist the NEM in catering for:

- **Almost double the electricity delivered to approximately 320 terawatt hours (TWh) per year.** Today the NEM delivers just under 180 TWh of electricity to industry and homes per year. The NEM would need to nearly double that by 2050 to serve the electrification of our transport, industry, office and homes, replacing gas, petrol and other fuels. That growth is needed in addition to significant ongoing investment by consumers in distributed energy and energy efficiency. The needs of proposed hydrogen production to export our abundant renewable energy potential, if supplied from the grid, would be additional to this growth and are explored further in AEMO's *Hydrogen Superpower* scenario.
- **Coal-fired generation withdrawing faster than announced, with 60% of capacity withdrawn by 2030.** Current announcements by thermal plant owners suggest that about 8 gigawatts (GW) of the current 23 GW of coal-fired generation capacity will withdraw by 2030. In the *Step Change* scenario, assessed by stakeholders as most likely, ISP modelling suggests that 14 GW would withdraw by 2030. Coal-fired generators are continuing to bring forward their withdrawal from the market – potentially by up to seven years to 2025 in the case of the Eraring Power Station. Competition, climate change and operational pressures will intensify with the ever-increasing penetration of firmed renewable generation.

Figure 1 Forecast NEM capacity to 2050, *Step Change* scenario



- **Nine times the utility-scale VRE capacity.** Australia is currently installing VRE faster than at any time in history. This record rate needs to be maintained every year for a decade to triple VRE capacity by 2030 – then almost double it again by 2040, and again by 2050. Much of this resource will be built in renewable energy zones (REZs) that coordinate network and renewable investment (including offshore wind REZ). These zones have the potential to foster a more holistic approach to regional employment, economic opportunity and community participation that may lead to greater local fulfilment of the NEM's supply chain needs.
- **Nearly five times the distributed PV capacity**, **and substantial growth in distributed storage.** The NEM's transformation will be influenced by the generation and feed-in capability of millions of individual consumer-owned solar PV systems. Today, ~30% of detached homes in the NEM have rooftop PV, their ~15 GW capacity meeting their owners' energy needs and exporting surplus back into the grid. By 2032, over half of the homes in the NEM are likely to do so, rising to 65% with 69 GW capacity by 2050, with most systems complemented by battery energy storage. Assuming that investment in distribution systems is coordinated with DER expansion for efficient operation and export, their 93 TWh of electricity would meet nearly one fifth of the NEM's total underlying demand.

Treble the firming capacity from dispatchable storage, hydro and gas-fired generation to firm renewables

As coal-fired generation withdraws and weather-dependent generation starts to dominate, the NEM must efficiently match when and where electricity is generated, with when and where it is needed. To do so, investment is needed to treble the firming capacity provided by new low-emission firming alternatives that can respond to a dispatch signal, with efficient network investment to access it.

Currently, the NEM relies on 23 GW of dispatchable firm capacity from coal-fired generation, 11 GW from gasfired and liquid-fuelled generation, 7 GW from hydro generation (excluding those that rely solely on pumped hydro to operate), and 1.5 GW from dispatchable energy storage (including pumped hydro and battery storage). [1]

Without coal-fired generation, the ISP modelling suggests that the NEM will require by 2050 the firming capacity set out below. However, the investment schedule will vary between types, and evolving economics will determine the actual level of investment in each of these technologies.

- **46 GW / 640 GWh (gigawatt hours) of dispatchable storage, in all its forms.** The most pressing need in the next decade (beyond what is already committed) is for dispatchable batteries, pumped hydro or alternative storage to manage daily and seasonal variations in the output from fast-growing solar and wind generation. By 2050, the ISP modelling recognises that VPPs, vehicle-to-grid (V2G) services and other emerging technologies will provide approximately 31 GW of dispatchable storage capacity, and utility-scale battery and pumped hydro storage 16 GW (see Figure 1). This balance of grid- and household-connected storage solutions reinforces the need for close collaboration between AEMO, network service providers (NSPs) and investors to ensure investments are synchronised to optimise benefits for consumers.

[1] The existing Snowy Hydro capacity (including Tumut 3) is categorised as hydro in this summary as it is predominantly reliant on natural inflows for its operation. The ability of Tumut 3 to pump water to manage storages is reflected in the ISP modelling.

- **7 GW of existing hydro generation**, both storage and run-of-river types, which rely entirely or predominantly on natural inflows rather than pumping to operate.
- **10 GW of gas-fired generation for peak loads and firming.** Gas-fired generation will play a crucial role as coal-fired generation retires. It will complement battery and pumped hydro generation in periods of peak demand, particularly during long 'dark and still' weather periods. It will help cover for planned maintenance of existing generation and transmission. And it will provide essential power system services to maintain grid security and stability, particularly following unexpected outages or earlier than expected generation withdrawal.

  This critical need for peaking gas-fired generation will remain through the ISP time horizon to 2050, and older and less efficient peaking plants may need to be replaced. Additional and earlier peaking gas-fired generation would add resilience against potential shortfalls in VRE, storage, DER or transmission. Over time, gas-fired generation emissions will need to be offset elsewhere if the economy is to reach net zero emissions, and natural gas may be replaced by net zero carbon fuels such as green hydrogen or biogas.

Wholesale demand response and other flexible loads will also help manage peak loads and troughs, reducing reliance on more capital-intensive investments while firming renewables.

These technologies are largely complementary; any shortfall in one area would require additional investment in another, and potentially significantly more in some cases, to cover any resulting gaps.

Market and technical reforms for system services and two-way electricity flow

Often overlooked in the calls for large physical infrastructure is the need for technical assessment and ingenuity in the way the power system of this scale is operated, made more complex by the demands of two-way electricity flow. Significant market and technical reforms are underway to manage a secure and efficient transformation to a low-emissions grid:

- **Significant market reforms have already been implemented.** On 1 October 2021, AEMO and its industry partners implemented Five Minute Settlement and Wholesale Demand Response in the NEM. These major reforms provide better price signals for fast response and flexible technologies, and enable businesses to provide peak shaving services in the spot energy market.
- **Further significant market reforms are underway.** AEMO is working with the Energy Security Board (ESB) and its members, the Australian Energy Regulator (AER) and Australian Energy Market Commission (AEMC), progressing reform workstreams and associated initiatives, including:
  - **A capacity mechanism** to create a clear, long-term signal for investment in both existing and new dispatchable capacity. Enhancements to Medium Term Projected Assessment of System Adequacy (MT PASA) are also in train to improve transparency of capacity which is available to the market.
  - **Essential System Services**, to progress and deliver a number of initiatives to maintain the system's secure operation and unlock value for consumers, including system strength, frequency, operating reserve and inertia.
  - **DER Integration** to ensure these resources are coordinated and aligned with system and market signals, including through some active management for efficient operation and export.
  - **Transmission reform** and **congestion management** mechanism, to consider the case for a congestion management mechanism to improve market signals for generator connections.

    The AEMC's Transmission Planning and Investment Review (TPIR) aims to ensure that future transmission infrastructure can be delivered in a timely and efficient manner to meet decarbonisation objectives, by proposing amendments to the existing regulatory framework to better facilitate key enablers such as social licence, an appropriate economic assessment framework including cost estimation accuracy, financeability and cost recovery. Incremental reforms will be proposed towards the end of 2022, while longer-term reforms will be proposed in 2023.

- **Collaborative framework for power system requirements**. AEMO's Engineering Framework[2] enables industry participants to collaboratively define the operational, technical and engineering requirements for the NEM's future, and informs the market reforms being undertaken by the ESB. It describes the initial roadmap for preparing the NEM to operate under six operational conditions (including contributing to 100% instantaneous renewable energy potential by 2025) and prioritises an initial set of initiatives. To ensure the NEM power system can operate securely with such high penetration of inverter-based resources, the system operator and network service providers will need to uplift their capabilities in operational systems, processes, real time monitoring and power system modelling. AEMO has developed a strategic roadmap for this uplift[3].

Transmission projects in the optimal development path

The new generation and storage opportunities above constitute the ISP development opportunities of the optimal development path (ODP) to 2050. The ODP also identifies 10,000 km of new transmission to connect these developments and efficiently deliver firmed renewable energy to consumers through the NEM. It identifies projects that are actionable now as well as in the future, and is selected from candidates in accordance with the Cost Benefit Analysis Guidelines made by the AER, as detailed in AEMO's *ISP Methodology*.

Those projects, listed in Table 1 and set out visually in Figure 2 below, are categorised as:

- Committed and anticipated projects already underway,
- Actionable projects, for which work should commence at the earliest planned time, and
- Future ISP projects, which may include the need for the transmission network service provider (TNSP) to undertake preparatory works or REZ Design Reports to enable more detailed consideration in the next ISP.

All actionable projects should progress as urgently as possible. Their delivery dates are largely dictated by their earliest practical delivery time as advised by the project proponents. In some cases, the optimal timing would be earlier than what is achievable; in others, any earlier delivery would provide valuable insurance against faster-than-expected coal closures or slower-than-expected VRE and storage development.

Support mechanisms such as the NSW Transmission Acceleration Fund, the Victorian Renewable Energy Development Plan and the Commonwealth Government's Rewiring the Nation policy or other jurisdictional Government policies and approaches may be able to assist in earlier delivery.

[2] See https://aemo.com.au/initiatives/major-programs/engineering-framework.

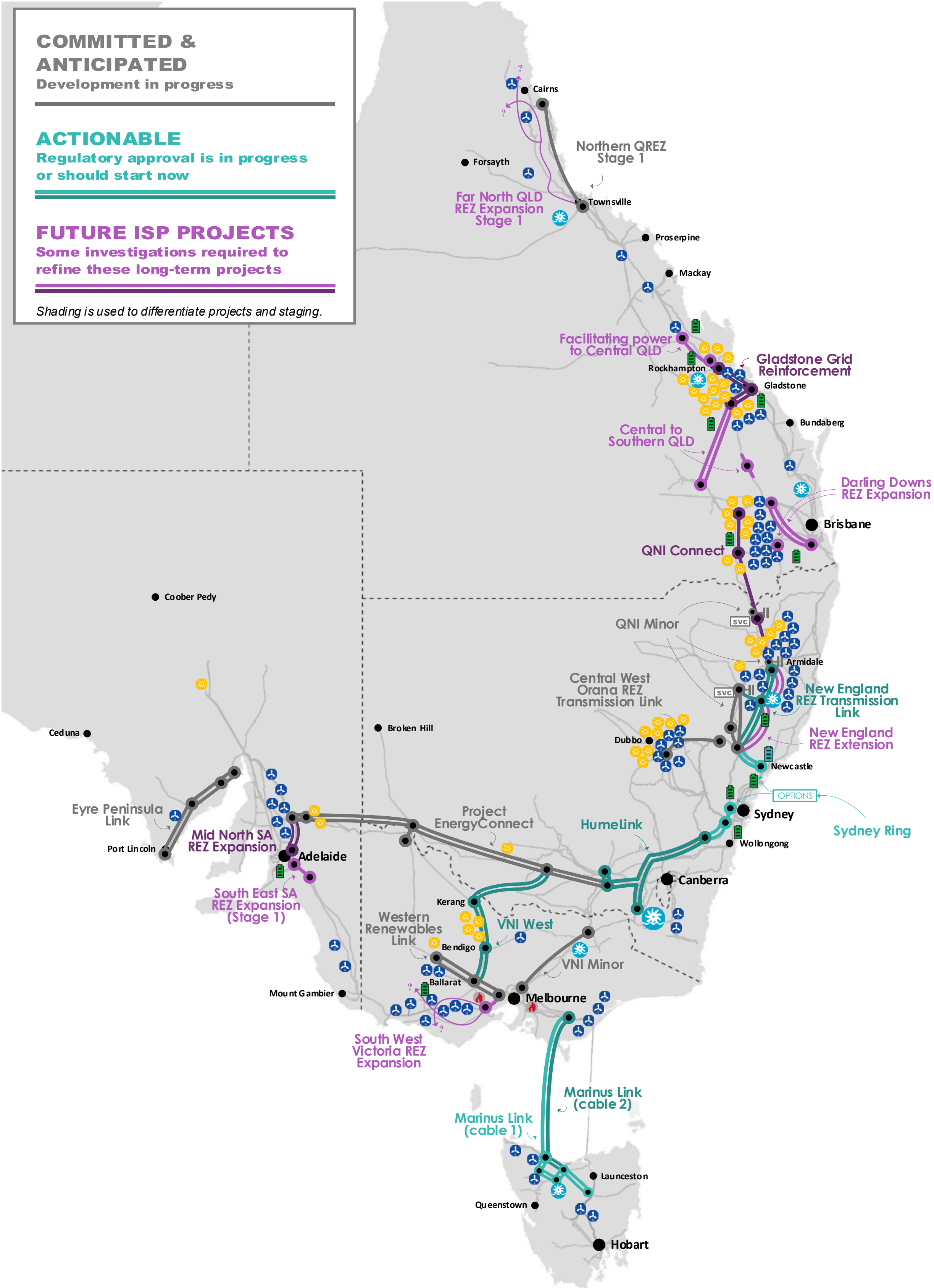
[3] See https://aemo.com.au/initiatives/major-programs/operations-technology-roadmap.

Table 1 Network projects in the ODP

Committed and anticipated ISP Projects	Delivery date advised by project proponent†	
VNI Minor: Victoria – New South Wales Interconnector Minor upgrade	November 2022	
Eyre Peninsula Link	Early-2023	
QNI Minor: Queensland – New South Wales Interconnector Minor upgrade	Mid-2023	
Northern QREZ Stage 1	September 2023	
Central West Orana REZ Transmission Link	July 2025	
Project EnergyConnect	July 2026	
Western Renewables Link *(formerly Western Victoria Transmission Network Project)*	July 2026	
Actionable Projects	**To be progressed urgently – latest delivery date**	**Actionable Framework**
HumeLink	July 2026	ISP
Sydney Ring (Reinforcing Sydney, Newcastle and Wollongong Supply) ¥	July 2027	NSW ‡
New England REZ Transmission Link	July 2027	NSW ‡
Marinus Link	Cable 1: July 2029 Cable 2: July 2031	ISP
VNI West (via Kerang)	July 2031, or earlier with additional support	ISP
Future ISP Projects		
Interconnector projects: QNI Connect		
New South Wales Projects: New England REZ Extension		
Queensland Projects: Central to Southern Queensland, Darling Downs REZ Expansion, Gladstone Grid Reinforcement, Far North Queensland REZ Expansion and Facilitating Power to Central Queensland		
South Australia Projects: South East South Australia REZ Expansion, Mid North SA REZ Expansion		
Victoria Projects: South West Victoria REZ Expansion		
Additional projects to expand REZs and upgrade flow paths beyond 2040, which are highly uncertain and vary between scenarios		

† Reflects the latest project timing for the full release of capacity as advised by the relevant TNSP.
‡ The New England REZ Transmission Link and Sydney Ring project are actionable NSW projects rather than actionable ISP projects. They will progress under the Electricity Infrastructure Investment Act 2020 (NSW) rather than the ISP framework.
¥ The northern part of this project is named the *Hunter Transmission Project* and may include the *Waratah Super Battery* and related upgrades.

Figure 2 Map of the network projects in the optimal development path



† Additional projects to expand REZs and upgrade flow paths after 2040 are highly uncertain, vary significantly between scenarios, and are not shown on this map. See Appendix 5 for more information.

Transmission projects enable the transformation, add $28 billion in value, and manage risk

The transmission projects within the ODP are forecast to deliver scenario-weighted net market benefits of $28 billion, returning around 2.2 times their cost of approximately $12.7 billion[4]. They represent just 7% of the total investment in NEM generation, storage, and network to 2050; optimise benefits for all who produce, consume and transport electricity in the market; and provide both investment certainty and the flexibility to reduce emissions faster if needed.

All of the transmission projects in the ODP are needed. They will cost-effectively serve the needs of consumers, support Australia's transition to net zero emissions, and support regional employment and economic growth.

After modelling the optimal timing of the projects through several candidate development paths, the ODP calls for delivery of all actionable projects as early as possible given their estimated delivery timeframes. Their optimal timing has been determined through extensive industry consultation to:

- Give greater market and price certainty and enhanced power system resilience as coal-fired power plants retire, especially if firming resources as projected in this ISP are not delivered in time to cover those retirements,
- Allow time for community co-design of project implementation, noting that many past infrastructure and resource projects in Australia have been delayed or withdrawn where proponents have not allowed enough time or mutuality in that engagement, and
- Allow flexibility in the procurement of expertise, materials and equipment, noting the forecast acceleration in global infrastructure and renewable energy investment over the next two decades.

Priority action on several fronts needed to implement the ISP

The pace of change and scale of investment in Australia's energy sector is already unprecedented, yet will only accelerate. It is imperative that the actionable projects (as well as the projects being progressed under the NSW framework) should commence on time, and be developed efficiently to the proposed timetables, to enable an efficient and effective energy transformation for consumers.

There are a range of urgent efforts required to support the ISP's timely implementation, and its central role in the Commonwealth Government's Rewiring the Nation policy. The Commonwealth and NEM state governments can assist in on-time or earlier delivery of these critical projects through supporting policies and cooperation to deliver ISP projects. A range of potential mechanisms could be developed, including: changes to the regulatory framework; financial mechanisms to better align benefits with costs and the timing of their imposition; government investment, underwriting or finance; and improved recognition of the impact on landholders and communities hosting the infrastructure.

AEMO understands it is the Commonwealth's intention to work collaboratively with jurisdictions and market bodies to ensure Rewiring the Nation and the wider Powering Australia program integrate with and complement jurisdictions' activities for maximum impact.

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[4] The network investment identified as actionable in this ISP is approximately $12.8 billion in today's value, and constitutes about 4% of the total spend needed to develop, operate and maintain the generation, storage and future network investments of the NEM to 2050 (in net present value [NPV] terms). Considering all transmission investments (actionable and future), the total transmission capital investment represents about 7% of the total spend (in NPV terms), delivering $28 billion of benefits to consumers.

Broadly, action is needed on the following fronts:

- **Immediate action to progress actionable projects**. To protect consumers against the risk of over-investment, the ISP process can tend to make an individual project actionable only when the benefits are clear and the project is somewhat urgent. Yet due to their scale and complexity, these projects are prone to delay, and late delivery could lead to more costs to consumers than early investment. Mechanisms which support earlier progression of projects can deliver cost savings in construction and earlier realisation of benefits. Government support through finance, underwriting or other measures, fast-tracked licencing and environmental assessments, and streamlining of the regulatory framework governing critical transmission projects identified in the ISP, would assist in accelerating their delivery to realise these potential benefits.
- **Preparatory Activities and REZ Design Reports** to progress the design of future ISP projects. This ISP triggers Preparatory Activities to improve the design for REZ expansions and flow path upgrades, and prepares for REZ Design Reports that may be triggered for REZ development opportunities that may be advanced. These processes improve the conceptual design, lead time and cost estimate of projects that feed into future ISPs. A number of jurisdictions are progressing REZ developments by proposing coordinated infrastructure development and streamlined connection processes. Some actions could be taken where projects are likely to yield significant benefits such as securing future transmission corridors. This may require supporting government policies or other investment.
- **Securing social licence for generation and transmission investments**. This ISP shows how the NEM can optimise consumer benefits, support national net zero objectives, and provide future economic opportunities. Substantially expanded community engagement programs that help to improve the recognition of these additional benefits may assist project proponents with securing appropriate social licence, as would the manner in which the engagement is conducted. Improved recognition of the impacts and greater sharing of the benefits with landholders and communities who are hosting renewable developments and transmission infrastructure could also assist with securing social licence for the necessary infrastructure developments.
- **Securing social licence for greater DER coordination.** Significant market reforms achieved since the 2020 ISP are supporting the technical integration of DER and other modern energy resources. The ISP assumes that all DER generation made available under each scenario can be exported into the network. Strong coordination of DER with system requirements as signalled by the market, including through some active management for efficient operation and export, is required to realise the optimal development path projections and optimise the NEM's net benefits, security and reliability. That in turn will rely on a step change in engagement between consumers, retailers, VPP operators, networks and other market participants to orchestrate their resources.
- **Coordination to improve supply chain efficiency and alleviate potential constraints.** The scale of engineering investment needed for the ODP is unprecedented in Australia's energy sector history. It will need to draw on local and international markets for funding, steel, concrete, engineering equipment and labour, and technical and project management skills. These markets are anticipated to be extremely tight over the coming two decades, as all national economies face the same net zero challenge.

- **Urgent action through AEMO's Engineering Framework**[5] to prepare the NEM for its future demands. Today's power system and its incremental reform trajectory were not designed for the scale and pace of disruptive transformation now underway. Instantaneous renewable penetration peaks in summer, has been rising at 6-7% each year, and reached a record 61.8% on 15 November 2021. AEMO forecasting indicates there will be enough potential renewable resource to reach 100% by 2025. The share of potential resource that is actually dispatched depends on a range of market factors. All NEM stakeholders are therefore collaborating towards a power system capable of operating with 100% instantaneous renewable penetration by 2025. The Engineering Framework and its work program define the priorities to realise this transition, and AEMO's annual system security and reliability reports focus on immediate performance.

These priority actions are needed to address a comprehensive set of transformation risks that have been considered in the ISP scenario and cost-benefit analyses. Delivering them will enable the ODP to deliver the market benefits articulated in this ISP, as well as improve regional economic and jobs growth, deliver needed and desired emission reductions, and improve resilience and adaptation for more extreme climate events.

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The NEM's transformation is essential for the Australian economy to achieve net zero emissions by 2050. The ISP sets out a roadmap for the NEM to make that long-term transition while continuing to prove itself day-in, day-out against complex operational realities. Those realities only confirm investment in firmed, renewable energy and essential transmission as the best strategy to manage future reliability and protect against higher prices.

When successful on this critical mission, the NEM will also be in a stronger position to support further economic opportunities that are being pursued across its jurisdictions, in new forms of energy exports, low-emission industrial production, and energy-intensive digital industries.

AEMO presents the 2022 ISP as a major and positive contribution towards the sustainable future of Australia's energy, economic, social and environmental systems. We sincerely thank all those who have contributed, and look forward to engaging with all energy market participants towards the next ISP.

[5] See https://aemo.com.au/initiatives/major-programs/engineering-framework.

Material changes from the Draft ISP

In response to feedback on the Draft ISP, and to account for investment and policy announcements and changing market conditions, AEMO has made the following changes from the draft to final ISP.

- **Clarifying that actionable projects should be progressed as soon as possible**. The schedule of actionable projects lists the earliest practical delivery time AEMO has been advised by the project proponents. Earlier delivery would either be more optimal to deliver benefits to consumers or would provide valuable insurance and guard against other potential delays. All actionable projects should therefore progress as urgently as possible, and state and Commonwealth mechanisms which support earlier progression of projects could deliver earlier benefits or cost savings.
- **Marinus Link** delivery timing has been advised as two years later, with updated cost estimates from the proponent. These recognise COVID-related delays and the need for inter-network testing (e.g. staged commissioning and capacity release).
- **HumeLink and VNI West decision rules** have been removed. As these projects remain staged in the ISP and will have staged Contingent Project Applications, the ISP Feedback Loop arrangements now apply to protect consumers against risks of increasing project costs.
- **Sydney Ring** and the **New England REZ Transmission Link** will progress via the NSW Infrastructure Roadmap (*Electricity Infrastructure Investment Act 2020*) rather than as actionable ISP projects, in line with New South Wales Government announcements.
- **Preparatory activities** have been declared for several future ISP projects including QNI Connect and REZ upgrades in South East South Australia, Mid North South Australia, Darling Downs and South West Victoria.
- **Far north Queensland,** updated modelling of network losses has weakened the signal for additional investment in generation and transmission.
- **Additional sensitivities** have been undertaken to test lower offshore wind costs and the Victorian Government's offshore wind directions paper, alternative uptake and coordination of distributed storage, additional utility-scale storage, low discount rates, and recent coal closure announcements.
- **Analysis of distributional effects and consumer risk asymmetry** has confirmed how transmission upgrades can provide insurance value to protect against high wholesale prices.
- **Expanded climate resilience modelling** has recalculated the impact of long 'dark and still' weather periods and the benefits of geographic diversity.

Part A
Meeting the ISP's challenge

Australia's energy sector has now commenced a complex and accelerating transformation, aimed at reducing both the sector's emissions and its long-term cost. Traditional generators are being replaced by consumer-led distributed energy resources (DER), utility-scale renewable energy, and new forms of dispatchable resources to firm those renewables. The National Electricity Market (NEM) must provide the power system assets and services to ensure these resources are efficient, safe, reliable and secure.

To meet its prescribed purpose, the 2022 *Integrated System Plan* (ISP)[6] sets out an optimal development path (ODP) which identifies investments that meet the future needs of the NEM, including actionable and future ISP projects (transmission projects or non-network options), and development opportunities in "distribution assets, generation, storage projects or demand-side developments that are consistent with the efficient development of the power system".[7] It guides investors and other decision-makers on the optimal timing and placement of those resources.

The ISP is published every two years as the NEM's operating environment changes. Over the last four years, the pace of the NEM's transformation has pushed the upper bounds of modelled expectations. The costs of utility-scale renewable energy and rooftop photovoltaic systems (PV) have continued to fall, new business models are driving rapid consumer adoption of DER, and coal closures have been brought forward. This rate of transformation will continue to accelerate, supported by NEM state government and Commonwealth Government policies which are largely aligned.

The accelerating shifts in technologies, government policies, participant behaviours and business models, not to mention the complexity of the system itself, mean a single pre-determined path is highly unlikely to fulfil its purpose. This ISP therefore takes a balanced risk-based approach to the NEM's future development, considering a range of scenarios and risks, and carefully examining the upsides and downsides of key decision points.

AEMO has consulted extensively for this 2022 ISP. AEMO engaged openly with NEM stakeholders to draft and publish the *2021 Inputs, Assumptions and Scenarios Report* (IASR)[8], the *ISP Methodology*[9] and the *2021 Transmission Cost Report*[10]. These reports have done much of the preparatory heavy-lifting for the ISP, which incorporates their content unless otherwise stated. The Draft 2022 ISP was published in December 2021, receiving broad endorsement along with valuable suggestions for input assumptions and other improvements.

Since then, momentum towards decarbonisation has accelerated, confirming the *Step Change* scenario as a solid foundation for planning NEM investment. Some coal-fired power stations have brought forward their planned exits, offshore wind generation has gained more support, and investors have focused even more on climate and environmental, social, and governance considerations.

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[6] The term "2022 ISP" refers to both the Draft ISP published in December 2021 and this final 2022 ISP.

[7] NER 5.10.2

[8] See https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-inputs-assumptions-and-scenarios-report.pdf?la=en.

[9] See https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/isp-methodology.

[10] See https://aemo.com.au/-/media/files/major-publications/isp/2021/transmission-cost-report.pdf?la=en.

The NEM state governments have sharpened their energy, electric vehicle, renewables and emissions abatement policies, with increased focus on a shift to electrification of the economy supported by firmed renewable energy. The Commonwealth Government intends to enable and support delivery of transmission investment needed for this transition with its Rewiring the Nation policy, which could take shape through a range of potential mechanisms such as changes to the regulatory framework, financial mechanisms to better align benefits with costs and the timing of their imposition, and improved recognition of the impact on landholders and communities hosting the required infrastructure.

On the other hand, supply chain limitations and other factors are threatening the planned delivery timelines of some transmission projects and have resulted in confirmed or potential changes to timing.

AEMO has finalised this 2022 ISP after considering and responding to the feedback on the Draft ISP and to market events, including those leading to AEMO suspending the NEM spot market in June 2022.

This Part A expands on the groundwork that has been completed for the ISP, setting out:

- **Section 1** – the objective of the 2022 ISP and the challenges it faces, and
- **Section 2** – the extensive consultation undertaken to agree on the scenarios, inputs and assumptions relied on by the ISP.

Part B then sets out the ISP development opportunities in generation, storage and system services needed to meet the NEM's needs, while Part C focuses on the optimal development path for transmission projects.

1 The ISP's purpose and challenge

The ISP's prescribed purpose is "to establish a whole-of-system plan for the efficient development of the [NEM] power system that achieves power system needs for a planning horizon of at least 20 years for the long-term interests of the consumers of electricity"[11].

This section first clarifies each of the underlined phrases in this purpose. It then considers the extent of the challenge this purpose represents, given the inherent and emerging complexities that the NEM faces. In particular, AEMO has considered the extent to which the NEM may rapidly and sustainably minimise its emissions intensity. This transformation must negotiate the complexities of the NEM's physical operating system, the rising need to secure community support, and the uncertainties of global events, policies and supply chains.

1.1 Interpreting the ISP's prescribed purpose

The whole NEM power system, through to 2050

The NEM is an intricate system of systems, which includes regulatory, market, policy and commercial components. At its centre is the power system, an inherently complex machine of transcontinental scale. This system is now experiencing the biggest and fastest transformation since its inception over 100 years ago.

The ISP is a whole-of-system plan to efficiently achieve power system needs through that transformational change, in the long-term interests of electricity consumers. AEMO has extended the ISP's planning horizon through to 2050, to reflect Australia's 2050 net zero emissions target.

The ISP takes into account:

- state, territory and Commonwealth government energy and environmental policies,
- projected trends in future electricity demand and generation,
- consumer-led DER investments, including customer storage, generation and demand side responses,
- the different network and non-network technologies needed for the power system transition, including for transmission, generation and storage,
- the design and implementation of new REZs,
- power system requirements[12] that must continue to be satisfied as new technologies are integrated, and
- the impacts of coupled sectors such as transport, gas and hydrogen.

As a rigorous whole-of-system plan, prepared in collaboration with NEM jurisdictional planners and policy-makers, energy consumers, asset owners and operators, and market bodies, the ISP is the most comprehensive and robust analysis of the future electricity needs for the NEM.

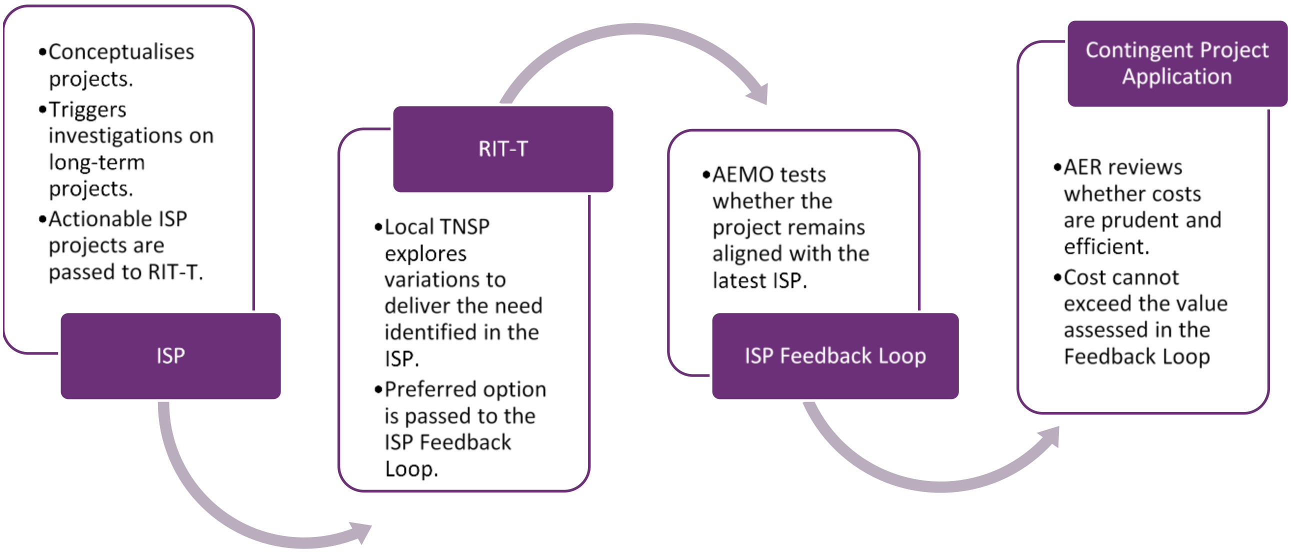
[11] NER 5.22.2

[12] See https://aemo.com.au/initiatives/major-programs/past-major-programs/future-power-system-security-program/power-system-requirements-paper.

Efficient development through a clear regulatory framework for projects

The ISP assists the efficient development of the NEM as part of a national transmission planning framework that ensures a clear assessment of ISP projects under the National Electricity Rules (NER). The core steps are set out in Figure 3 and described below, although there are multiple opportunities to challenge, review and change projects through what is an extremely rigorous process.

Figure 3 Summary of the economic assessment framework for actionable ISP projects (NEM)



The ISP assesses a range of candidate projects which may form part of the Optimal Development Path (ODP). These projects are classed as either actionable (for the project to be delivered to its earliest schedule) or future (likely to become actionable in the future).

Making a project actionable in the ISP triggers a Regulatory Investment Test for Transmission (RIT-T). The proponent Transmission Network Service Provider (TNSP) prepares a Project Assessment Draft Report (PADR) offering credible technical options for the project, upon which there is considerable stakeholder consultation.

In the ISP Feedback Loop, the TNSP takes its preferred option to AEMO to consider any new and relevant information, and confirm that the project would address the identified ISP need as part of the ODP.

Finally, the TNSP submits a contingent project application (CPA) to the Australian Energy Regulator (AER) to confirm that the costs associated with the actionable ISP project are prudent and efficient, and enable revenue recovery by the TNSP for the project. To protect consumers, the costs submitted in the CPA cannot exceed the costs submitted to AEMO in the feedback loop.

Power system requirements

NEM power system requirements are the reliability and security needs for operating a power system within operating limits and in accordance with operating standards. Table 2 summarises the fundamental power system requirements that are considered in the ISP. Primary among these is that the system remains in a satisfactory operating state through a contingency event[13] and can be returned to a secure operating state within 30 minutes. Appendix 7 provides more detail on the power system security needs as the NEM transforms from a power system dominated by large thermal power stations to a system that is more decentralised.

Table 2 Power system requirements considered in the ISP

Need	Operational requirements considered when developing the ISP	
Reliability	**Resource adequacy and capability** • There is a sufficient overall portfolio of energy resources to continuously achieve the real-time balancing of supply and demand.	Energy resources provide sufficient supply to match demand from consumers at least 99.998% of the time.
		Operating reserves exist to provide the capability to respond to large continuing changes in energy requirements.
		Network capability is sufficient to transport energy to consumers.
Security	**Frequency management and inertia response** • Ability to maintain system frequency within operating standards.	Frequency remains within operating standards – considering primary frequency response and frequency controls, minimum inertia requirements, and the availability of alternatives; the system is maintained within transient and oscillatory stability limits.
	Voltage management and system strength • Ability to maintain voltages on the network within acceptable limits. • System strength is above minimum levels.	Voltage remains within operating standards, fault levels are below equipment ratings, and system strength/fault levels are maintained above minimum requirements.

Public policies considered

In determining these power system needs, AEMO may consider the current environmental or energy policies of the NEM jurisdictions.[14] In this ISP, the following policies are included in its assumptions:

- **Emissions reduction targets.** Australia has committed to a net zero emissions target by 2050, and has committed a 2030 nationally-determined contribution (NDC) to the Paris Agreement targeted greenhouse gas emissions reduction (economy-wide) by 26-28% below 2005 levels. This target is included in forecast assumptions. Australia's recent update to its 2030 NDC, to 43% emissions reduction below 2005 levels, has not applied in all scenarios but is closely aligned with the *Step Change* scenario.
- **Renewable Energy Targets (RETs)** for Victoria, Queensland and Tasmania. AEMO applies a linear development trajectory to meet the RET targets, starting from the latest forecasts of existing, committed and anticipated renewable energy. For Victoria, this also includes the development requirements anticipated by the second Victorian Renewable Energy Target (VRET2)[15] auction process.
- **Policies affecting REZs and associated transmission.** For New South Wales, AEMO applies a generation development trajectory at least as fast as that specified in the Consumer Trustee's 2021 Infrastructure Investment Opportunities (IIO) Report[16].
- **DER policies.** AEMO incorporates each of these schemes in its DER uptake and behavioural analysis[17].

[13] An event affecting the power system which AEMO expects would be likely to involve the failure or removal from operational service of one or more generating units and/or transmission elements.

[14] NER 5.22.3(b)

[15] Further details available at https://www.energy.vic.gov.au/renewable-energy/vret2.

[16] See https://aemo.com.au/-/media/files/about_aemo/aemo-services/iio-report-2021.pdf?la=en.

[17] See Appendix A3 of the *Electricity Demand Forecasting Methodology* for details of the approach to incorporate DER. Available at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-approach.

- **Electric vehicle (EV) policies.** The EV policies within NEM jurisdictions[18] are included in electricity demand forecasts and apply them to all scenarios. *Slow Change* follows the targets, but ultimately falls short in a slower economy[19]. Some vehicle-to-grid (V2G) services are also assumed in all scenarios.
- **Energy efficiency policies.** Both Commonwealth and NEM state government policies are incorporated into electricity demand forecasts for all scenarios. These include building and equipment energy performance standards and ratings, and energy savings or efficiency schemes.

Long-term interests and net market benefits

The ISP must pursue its purpose in the long-term interests of electricity consumers. This is measured primarily by the net market benefits that a development path will bring to those consumers, although AEMO may justify the inclusion of other factors (see Section 6). The extensive classes of market benefits and costs that are included in this calculation are set out in the NER (rule 5.22.10). As detailed in the *ISP Methodology*, these market benefits align with the categories in the RIT-Ts.

In most cases, assuming an efficient market, the greatest net market benefits will arise from the lowest long-term system costs. Table 3 sets out the classes of market benefits and costs the ISP must consider in terms of operation and capital costs. As perfect foresight of future events is unlikely, these market benefits include the option value of an asset which is likely to be highly desirable in the future, but whose ultimate need or timing may not be certain. This option value may be realised by staging a project: starting it now on the information available to ensure it can be delivered as early as needed under some scenarios, with the option to pause development based on the best information available at a later time.

All values presented in this report are 30 June 2021 real dollars unless stated otherwise.

Table 3 Optimal net market benefits seen as minimal long-term system costs

Benefit	Realised 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 does not play out, and the value of staging	Lost options/flexibility

18 No new EV policies have been formally announced by the new Australian Government at the time of publication of the ISP. If announced, they are likely to accelerate the projected adoption of EVs.

19 See IASR Section 3.3.5 and CSIRO's *ElectricVehicle Projections 2021* report, at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

1.2 The complex race to net zero emissions

The Commonwealth and all NEM state governments have now confirmed the objective of a net zero emission economy by 2050 or sooner. Not only is the NEM expected to significantly reduce its carbon emissions, but it is a critical enabler for the industrial, transport and other domestic sectors to reach their net zero emissions objectives through electrification. As a result, the ISP must help guide the NEM through:

- the inherent complexities in its physical system,
- the challenge of switching to renewables while increasing electricity demand from newly electrified consumers, and
- the uncertainties of the global energy market and supply chain constraints.

The physical system is complex enough

The inherent complexities in operating the NEM's physical system include:

- increasing levels of consumer-driven DER,
- uncertainties in the timing of and market response to the retirement of coal-fired generators,
- satisfying the critical operational needs for the power system as system services from fossil-fuelled generators decline, and
- uncertain yet intensifying climate change impacts.

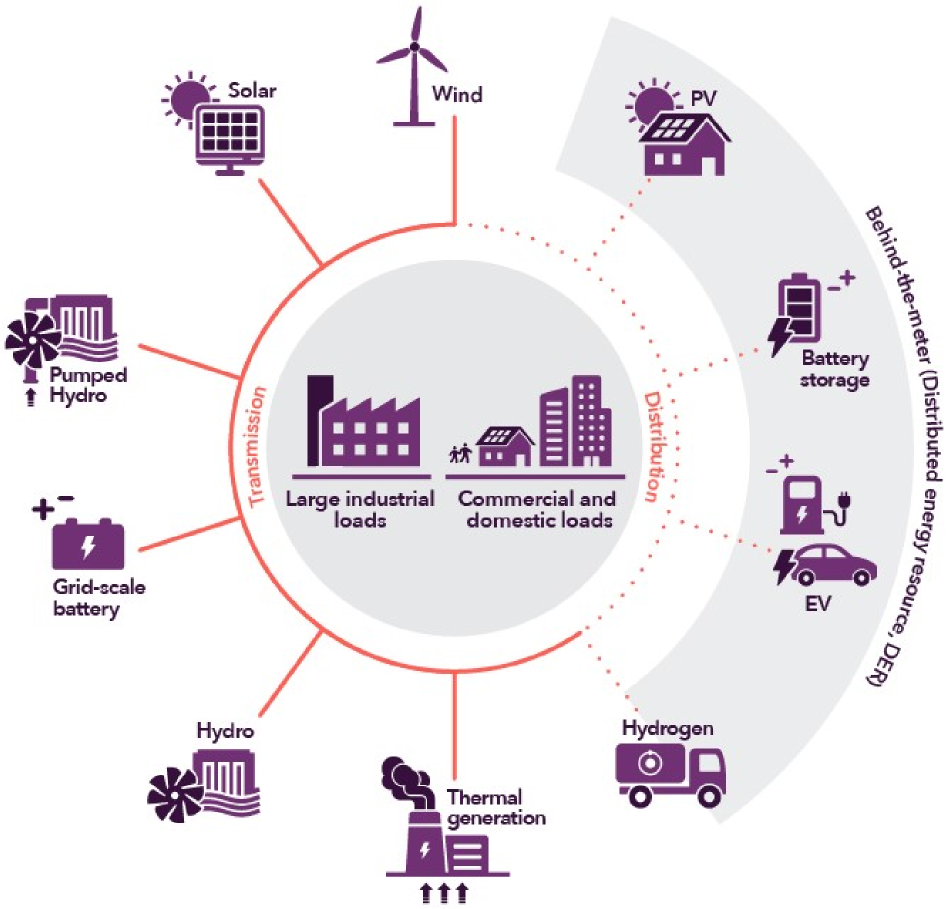
The first major complexity is the interaction between DER and utility-scale supply (see Figure 4). As more behind-the-meter PV is installed, and more batteries and EVs charge and discharge, the demand profiles for grid-supplied energy shift. This in turn influences how generators operate, and increases the value of flexible generation, storage and loads in the power system.

The second major complexity for the ISP is forecasting when existing coal plants will reduce generation, temporarily withdraw units from the NEM, or shut down. Owners of coal-fired generators have already either brought forward their announced retirements or indicated that they would, citing market, financial and operating pressures from the rise in renewable generation. The future of remaining thermal generation will become increasingly uncertain, particularly for older coal-fired generation that is less able to deliver the flexible dispatchable capacity needed to firm renewables. Significant plant refurbishments may also be harder to justify under this uncertainty, potentially resulting in declining plant reliability.

Asset owners make these decisions based on a range of commercial factors, in the context of energy and climate change policies, market arrangements, competing technologies, and social and investor licences. These traditional assets have guided the NEM's design, construction and operation to date. Their replacement with DER, variable renewable energy (VRE) and alternate dispatchable resources also means a transformational modernisation of the NEM's operations, including the system services which synchronous generators have traditionally delivered.

As sun, wind and water become the NEM's primary energy resources, supported by gas or other carbon-neutral fuels, it will become increasingly complex to preserve the resilience of the system against a broad array of extreme weather and climate impacts. System resilience is enhanced through fuel diversity, geographic diversity and strategic redundancy, and with design standards that meet Australia's expected climate and often high temperatures. Gas-fired generation, potentially fuelled by hydrogen, will play a crucial role as coal-fired generation retires, both to help manage extended periods of low VRE output and to provide power system services to provide grid security and stability (see Section 4.3).

Figure 4 Power system interactions between grid and behind-the-meter energy supply



Reducing emissions while increasing supply adds to the complexity

The NEM's operating environment is always subject to an array of economic, trade, security, policy (including on-land gas extraction) and technology environments, as set out in the 2020 ISP. The speed and scale of the transformation to a low-emission NEM poses a unique set of challenges. Not only is there a shift in generation from coal- and gas-fired generation to renewables but, as set out in Section 3, the electrification of transport, households and industry will double demand for electricity in the NEM over the same period.

So far, the NEM's transformation has outpaced all expectations. On a per capita basis, Australia added over four times the VRE the European Union did in 2018, and five times in 2019[20]. In the last two years, through the pandemic, VRE development accelerated, with 40% more VRE now committed or anticipated to be connected to the grid by 2023-24 than was forecast in the 2020 ISP. By May 2021, instantaneous renewable

[20] Blakers et al. 'Pathway to 100% renewable electricity', *IEEE Journal of Photovoltaics*, vol. 9, no. 6, November 2019.

penetration[21] (the industry measure of the share of grid consumption met by dispatched renewable energy), reached a record 57%. That record rose twice in September 2021, and then reached a new record of 61.8% on 15 November 2021.

AEMO forecasts there will be enough potential renewable resource in the NEM to reach 100% of grid demand by 2025. The share of potential resource that is actually dispatched depends on a range of market factors. Given uncertainties in the reliability of some fossil-fuelled generation, NEM stakeholders are therefore collaborating towards a power system capable of operating with 100% instantaneous renewable penetration by 2025.

Operating with community support

As the rate and scale of transformation continue to accelerate (see Part C), social licence will require urgent and continuing focus. There is a need to secure support from First Nation representatives, communities, and land owners, for the large amount of VRE, storage, and network development signalled in this plan. While generation, transmission and distribution assets have always been a difficult local planning issue, the transformation will require greater local support for the proposed use of land, potentially including dual-use considerations.

Operating in a global market

Finally, the NEM is not insulated from global markets, nor is Australia alone in its race to decarbonise. The already heavy investment in global power systems is expected to surge in the wake of both European conflict and COP26[22].

The Russian invasion of Ukraine has disrupted international energy markets and supply chains and resulting in temporarily high fuel prices internationally and domestically, leading to the application of regulated market price caps in the gas and electricity spot markets. In combination with high demands and plant outages, these conditions resulted in the need for unprecedented levels of intervention by AEMO, and ultimately the temporary suspension of the electricity spot market in all regions of the NEM. In the long term, this provides further evidence for the three intrinsic benefits from investment in renewables: to reduce the cost of energy, to increase energy security, and to reduce emissions.

The surge of energy investment also comes on top of a long-running and accelerating global boom in infrastructure investment – from a public perspective to catch-up on infrastructure needs, and from an investor perspective as a newly favoured asset class. These trends will require continued focus on supply chain reliability, availability of skilled labour, and cost management for power system development in Australia. Some actionable ISP projects have already experienced schedule delays, and such slippages are likely to continue.

The ISP aims to consider and model these variables and complexities in the most rigorous way possible.

The following section sets out how AEMO has consulted with stakeholders to settle on the scenarios upon which that analysis relies.

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[21] Instantaneous renewable penetration is calculated as the renewable generation share of total large- and small-scale generation. The measure is calculated on a half-hourly basis because this is the granularity of estimated output data for historical distributed PV output. For this calculation, renewable generation includes grid-scale wind and solar, hydro generation, biomass, battery generation and distributed PV, and excludes battery load and hydro pumping. Projected data has been adjusted to account for outages, constraints and time resolution differences.

[22] The 26th Conference of the Parties to the UN Framework Convention on Climate Change, Glasgow, November 2021.

2 Consultative modelling for the ISP

As discussed in Section 1, the challenge for the ISP is to meet power system needs in the long-term interests of the consumers of electricity, responding to government policies for decarbonisation. This is a complex challenge, to which all NEM participants and stakeholders have risen through the ISP consultation process.

This section briefly summarises the modelling process of the ISP to achieve that purpose. It sets out:

- the extensive industry consultation on the ISP methodology, inputs and scenarios, as well as through the Draft ISP process (Section 2.1)
- the scenarios developed through that consultation to consider the future possibilities, with the selection of *Step Change* as the scenario that stakeholders believe is most likely (Section 2.2), and
- the modelling used to determine how the NEM could optimally meet its electricity demand and emission reduction objectives for consumers (Section 2.3).

The results of this modelling are set out in Parts B and C of this ISP.

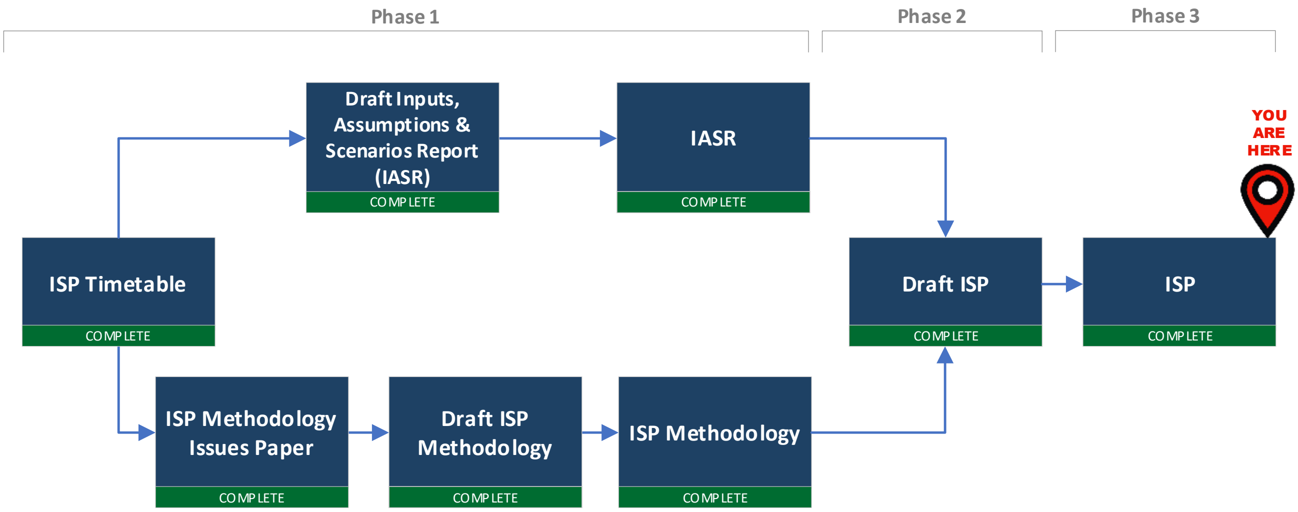
2.1 Consultations to date

Consultations for the ISP commenced in September 2020, and continued through three phases:

- **The first phase culminated in the 2021 IASR[23] and the *ISP Methodology*[24]**, published on 30 July 2021.
  - Those reports benefited from the insights of industry and consumer stakeholders over 10 months, through 88 detailed written submissions, four workshops and numerous stakeholder meetings (see Figure 5).
- The **second phase culminated in the Draft 2022 ISP**, published on 10 December 2021. AEMO conducted broad consultation with industry and consumer stakeholders on all aspects of the IASR and *ISP Methodology* as soon as they were published, with an additional forum on competition benefits in October 2021.
  - The AER published its transparency review on the 2021 IASR on 30 August 2021. Its review report concluded that the majority of AEMO's inputs and assumptions were adequately explained and that AEMO had demonstrated that it had taken into account stakeholder feedback. It also called for an addendum to the IASR, which AEMO published on 10 December 2021.
  - The five-member ISP Consumer Panel delivered its statutory report on the IASR on 30 September 2021, making 23 recommendations and stating that the evidence and reasons supporting the IASR were sound and the selected scenarios are appropriate.
- **The third phase has culminated in this 2022 ISP**, after considering comprehensive stakeholder feedback on the Draft ISP.
  - The AER published its transparency review on the Draft 2022 ISP on 7 January 2022[25], then AEMO published a Draft ISP Addendum[26] on 11 March 2022 to clarify several outcomes. The feedback to the Draft ISP and Draft ISP Addendum is described below.

[23] See https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-inputs-assumptions-and-scenarios-report.pdf?la=en.
[24] See https://www.aemo.com.au/-/media/files/major-publications/isp/2021/2021-isp-methodology.pdf?la=en
[25] See https://www.aer.gov.au/networks-pipelines/performance-reporting/transparency-review-of-aemo-draft-2022-integrated-system-plan.
[26] See https://aemo.com.au/consultations/current-and-closed-consultations/2022-draft-isp-addendum-consultation.

Figure 5 Parallel ISP consultations



Consultation and market developments since the Draft 2022 ISP

Unless otherwise noted, the 2022 ISP builds on the sound process and analysis of the Draft ISP. Since the Draft ISP, three sets of considerations have informed AEMO's work:

- AEMO received 78 submissions on the Draft ISP and its Addendum, resulting in changes to some input assumptions, additional sensitivity analysis, and further consideration of various risks and uncertainties. The submissions also influenced how some of the outcomes of the ISP have been communicated in this report and in the accompanying appendices. AEMO's responses to these submissions are detailed in the *2022 ISP Consultation Summary Report*.
- Several market developments have led AEMO to revise some input assumptions and sensitivity analyses. Most notable is the notice of the potential closure of Eraring Power Station in 2025, and the bringing forward of closures of the Bayswater and Loy Yang A power stations (to 2033 and 2045 respectively). Assumptions and analyses have also been updated to reflect an acceleration of committed generation capacity, as well as additional sensitivity analysis to isolate the impact of lower distributed storage uptake, and low discount rates.
- Potential changes to NEM jurisdiction policies have led AEMO to consider the power system resilience that the ODP may support, and the robustness of these potential investments to broader assumptions. One possibility is signalled by the Victorian Government's offshore wind directions paper[27], leading to additional sensitivity analysis to understand the potential impact of significant offshore wind in Victoria.

These additional analyses have focused on the timing of three nationally strategic projects – HumeLink, Marinus Link and Victoria – New South Wales Interconnector (VNI) West. They have focused on *Step Change* as the most likely scenario, but considered all scenarios where required to perform the appropriate cost-benefit analysis on alternative pathways. As will be discussed in Section 6, the additional analyses have not changed the rankings of the candidate development paths (CDPs), nor the selection of the ODP.

As part of future ISP processes, AEMO will continue to work with all governments to ensure that the ISP continues to meet the needs of consumers, the energy sector, industry and Government. This includes

[27] Victorian Government. *Victorian Offshore Wind Policy Directions Paper*, at https://www.energy.vic.gov.au/renewable-energy/offshore-wind.

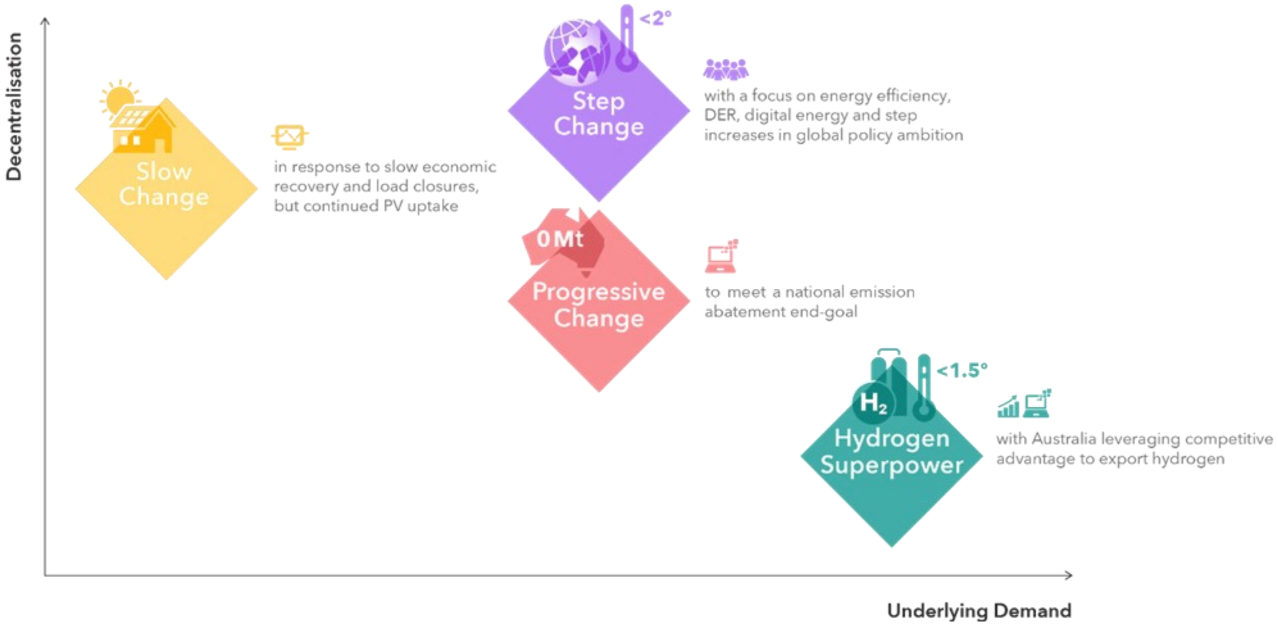
incorporating any changes to policies and programs that may occur. Such policies would be reviewed for the scheduled 2023 IASR, and feed into the 2024 ISP, or any earlier ISP update.

2.2 Four scenarios to span a range of plausible futures

Five scenarios were developed through industry consultations and published in the 2021 IASR. Further consultations determined the *Steady Progress* scenario to be no longer relevant for this ISP, given Australia's commitment to net zero emissions by 2050, and that the *Slow Change* scenario already tested the impact of slower than anticipated emission reduction.

The four remaining scenarios span a range of plausible futures with varying rates of emission reduction, electricity demand, and decentralisation (see Figure 6). The scale of electricity demand is influenced by the extent to which other sectors electrify (for example, the transportation sector via EVs). 'Decentralisation' is the extent to which business and household consumers manage their own electricity generation, storage or services, rather than just draw power from the grid. In the case of *Hydrogen Superpower*, this decentralisation is swamped by the scale of electricity demand needed for a hydrogen export industry.

Figure 6 Scenarios used for the 2022 ISP



Diverse future demand scenarios

The scenario broad descriptions are:

- ***Slow Change* – challenging economic environment** following the COVID-19 pandemic, with greater risk of industrial load closures, and slower net zero emissions action. Consumers continue to manage their energy needs through DER, particularly distributed PV. However, *Slow Change* would not reach the economy-wide decarbonisation objectives of Australia's Emissions Reduction Plan.
- ***Progressive Change* – pursuing an economy-wide net zero emissions 2050 target progressively, ratcheting up emissions reduction goals over time.** *Progressive Change* delivers a net zero emission economy, with a progressive build-up of momentum ending with deep cuts in emissions across the

economy from the 2040s. The 2020s would continue the current impressive trends of the NEM's emission reductions, assisted by government policies, consumer DER investment, corporate emission abatement, and technology cost reductions. The 2030s would see commercially viable alternatives to emissions-intensive heavy industry emerge after a decade or longer of research and development, paving the way for stronger economy-wide decarbonisation and industrial electrification in the 2040s, and nearly doubling the total capacity of the NEM. EVs become more prevalent over time and consumers gradually switch to using electricity to heat their homes and businesses. Some domestic hydrogen production supports the transport sector and as a blended pipeline gas, with some industrial applications after 2045.

- ***Step Change* – rapid consumer-led transformation of the energy sector and co-ordinated economy-wide action.** *Step Change* moves much faster initially to fulfilling Australia's net zero policy commitments that would further help to limit global temperature rise to below 2°C compared to pre-industrial levels. Rather than building momentum as *Progressive Change* does, *Step Change* sees a consistently fast-paced transition from fossil fuel to renewable energy in the NEM. On top of the *Progressive Change* assumptions, there is also a step change in global policy commitments, supported by rapidly falling costs of energy production, including consumer devices. Increased digitalisation helps both demand management and grid flexibility, and energy efficiency is as important as electrification. By 2050, most consumers rely on electricity for heating and transport, and the global manufacture of internal-combustion vehicles has all but ceased. Some domestic hydrogen production supports the transport sector and as a blended pipeline gas, with some industrial applications after 2040.
- ***Hydrogen Superpower* – strong global action and significant technological breakthroughs.** While the two previous scenarios assume the same doubling of demand for electricity to support industry decarbonisation, *Hydrogen Superpower* nearly quadruples NEM energy consumption to support a hydrogen export industry. The technology transforms transport and domestic manufacturing, and renewable energy exports become a significant Australian export, retaining Australia's place as a global energy resource. As well, households with gas connections progressively switch to a hydrogen-gas blend, before appliance upgrades achieve 100% hydrogen use.

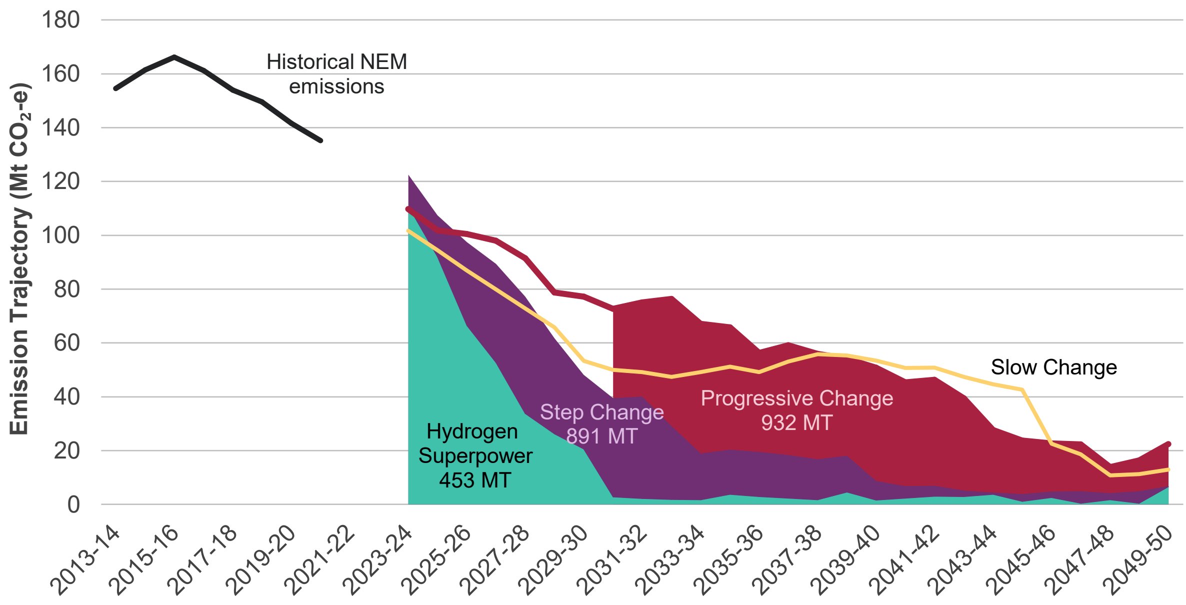
Figure 7 Scenario input assumptions

DEMAND	Slow Change		Progressive Change		Step Change		Hydrogen Superpower	
Electrification	**2030**	**2050**	**2030**	**2050**	**2030**	**2050**	**2030**	**2050**
– Road transport that is EV (%)	2	36	5	84	12	99	18	94
– Residential EVs still relying on convenience charging (%)	82	58	75	44	70	31	66	22
– Industrial Electrification (TWh)	-24	-21	4	92	27	54	37	64
– Residential Electrification (TWh)	0	0	0.2	15	4	13	2	4
– Energy efficiency savings (TWh)	8	19	14	40	22	55	22	56
Underlying Consumption								
– NEM Underlying Consumption (TWh)	163	213	201	394	222	336	243	330
– Hydrogen consumption – domestic (TWh)	0	0	0	32	0.1	58	2	132
– Hydrogen consumption – export, incl. green steel (TWh)	0	0	0	0	0	0	49	816
– Total underlying consumption (TWh)	**163**	**213**	**201**	**425**	**223**	**394**	**294**	**1,278**
SUPPLY								
Distributed PV Generation (TWh)	39	58	39	80	45	93	51	112
Household daily consumption potential stored in batteries (%)	3	5	5	22	12	38	13	39
Underlying consumption met by DER (%)	24	27	20	19	20	24	17	9
Coal generation (% of total electricity production)	32	5	38	2	21	0	6	0
NEM emissions (MT CO_2-e)	53.3	13.0	77.2	22.4	48.1	6.8	20.6	6.6
2020 NEM emissions (% of)	38	9	54	16	34	5	15	5

Emissions reduction targets and trajectories for the scenarios

Included in these assumptions are carbon budgets for the electricity sector itself – that is, the NEM's contribution to reducing Australia's emissions to net zero by 2050. Figure 8 below sets out the emission reduction trajectory for the electricity sector in each scenario. While most scenarios get to net zero by 2050, each takes a different approach. *Progressive Change* gets there 'just in time', while *Step Change* and *Hydrogen Superpower* move faster to approach or reach net zero by 2035. *Slow Change* sees reductions in emissions early due to assumed load closures, but abatement then slows considerably in the second and third decade, and lacks economy-wide electrification.

Figure 8 NEM carbon budgets and the resulting emission trajectories



To determine these carbon budgets, AEMO and its consultants (CSIRO and ClimateWorks) considered four means (or "pillars") by which to decarbonise the economy. The decarbonisation of the NEM is a key pillar, which influences, and is influenced by, shifts in the other three:

- **Electricity sector decarbonisation**, being the speed at which the carbon intensity of electricity generation approaches zero.
- **Fuel-switching** from fossil fuels to zero or near-zero emissions alternatives, including electrification. By 2050, at least 150 terawatt hours (TWh) of new consumption is forecast from the switching of other energy sources to electricity, almost doubling today's delivered consumption of approximately 180 TWh per year. Heating, cooking, hot water and almost all transport and industrial processes are able to be electrified. As some electrification is more expensive than others, the level increases over time in all scenarios as emission targets tighten and/or technology breakthroughs reduce the cost of fuel-switching.
  - As the price of EVs falls, for example, their share of the total vehicle fleet is expected to increase, rising in *Step Change* to 58% by 2040. This would account for approximately 37 TWh of electricity demand, with a demand profile that would ideally provide a sponge for solar supply, but may exacerbate peak demands without proper infrastructure and consumer incentives to charge outside those periods.
- **Energy efficiency** through improved energy productivity and waste reduction.

- **Carbon offsets** through non-energy emission reductions and sequestration, with technology-based carbon sequestration likely accounting for 3-10% of all sequestered carbon (depending on the scenario).

2.3 *Step Change* scenario most likely

Step Change is considered by energy industry stakeholders to be the most likely scenario to play out, ahead of the *Progressive Change* scenario. This was the conclusion of a careful process in 2021 through which AEMO twice convened a panel of Australian energy market experts representing all stakeholder groups, with an intervening round of public consultation. The events of 2022 have been more aligned with *Step Change* than any other scenario.

- **First panel considers two scenarios equally likely.** The panel of experts representing government, market bodies, generators, consumer and network service providers first met on 5 October 2021, prior to Australia's net zero emissions commitments at COP26[28]. They deliberated using a Delphi Technique to anonymously rate the scenarios, offer reasons for those ratings, and consider the responses of others to revise their ratings if appropriate. In this first forum, *Step Change* and *Progressive Change* each earned over one-third of participant votes, with *Hydrogen Superpower* and *Steady Progress* splitting most of the remainder, and very few votes expecting *Slow Change* to play out.
- **Public forum tests the panel findings.** AEMO then held a public forum on 22 October 2021, ahead of COP26, to share the first Panel's views. Stakeholders at the forum considered any commitment to net zero emissions would require the Delphi Panel to reconsider their weightings: see Appendix 1.
- **Second panel prefers *Step Change.*** The same experts from the first panel were invited back to repeat the Delphi process on 16 November 2021, following COP26. In this second sitting, the panel considered that the *Steady Progress* scenario (with its failure to meet net zero ambitions) was no longer appropriate, and that the ISP focus its modelling on the remaining four scenarios. In considering those four, the panel concluded that the *Step Change* scenario was the clear 'most likely' scenario, securing approximately half of all votes, followed by *Progressive Change* and then *Hydrogen Superpower*. Again, *Slow Change* received very few votes.

The final weighting for *Step Change* reflected the Panel's view that emission reductions are accelerating across the economy.

Through 2022, market settings towards decarbonisation have accelerated, confirming *Step Change* as a solid foundation for planning NEM investment. Some coal-fired power stations have brought forward their planned exits, offshore wind generation has gained more support, several NEM jurisdictions have sharpened their energy, electric vehicle and emissions policies, and investors have focused even more on climate and environmental, social and governance considerations. In addition, the Commonwealth Government has flagged its intent to accelerate delivery of transmission investment in its Rewiring the Nation policy.

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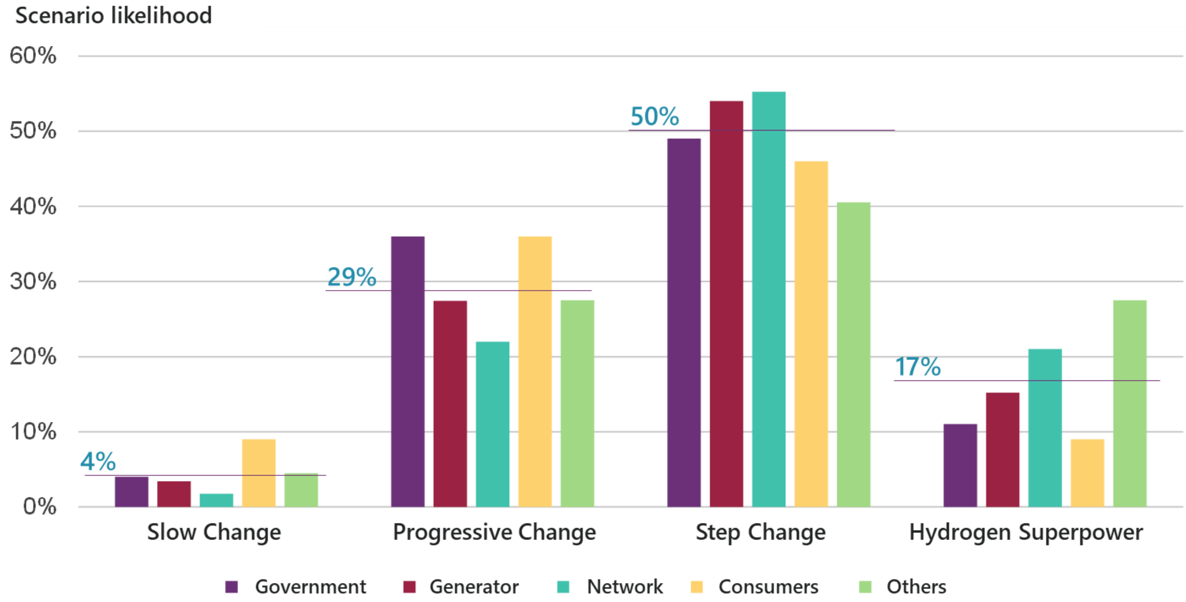
[28] The 26th Conference of the Parties to the UN Framework Convention on Climate Change, Glasgow, November 2021.

Figure 9 Scenario weightings, second Delphi panel (by stakeholder group)



2.4 Modelling of the power system to meet targets

All scenarios and potential power system investments have been analysed through an integrated suite of forecasting and planning models and assessments, to determine which investments would form the optimal development path. It is an iterative approach, where the outputs of each process may determine or refine inputs into others. An overview of the integrated suite is shown in Figure 10, and provided in detail in the *ISP Methodology*[29].

These models rely on key fixed and modelled inputs for each scenario defined in the 2021 IASR[30], part of the comprehensive stakeholder engagement to inform the 2022 ISP. For the first time, the inputs include economy-wide emission reduction initiatives to meet the net-zero target, and include a new public database on transmission costs, a world-leading initiative to provide transparency for regulated transmission builds. The database offers a significant volume of updated inputs from past assessments, and clearly itemises changes since the 2020 ISP.

The model components can be summarised as follows:

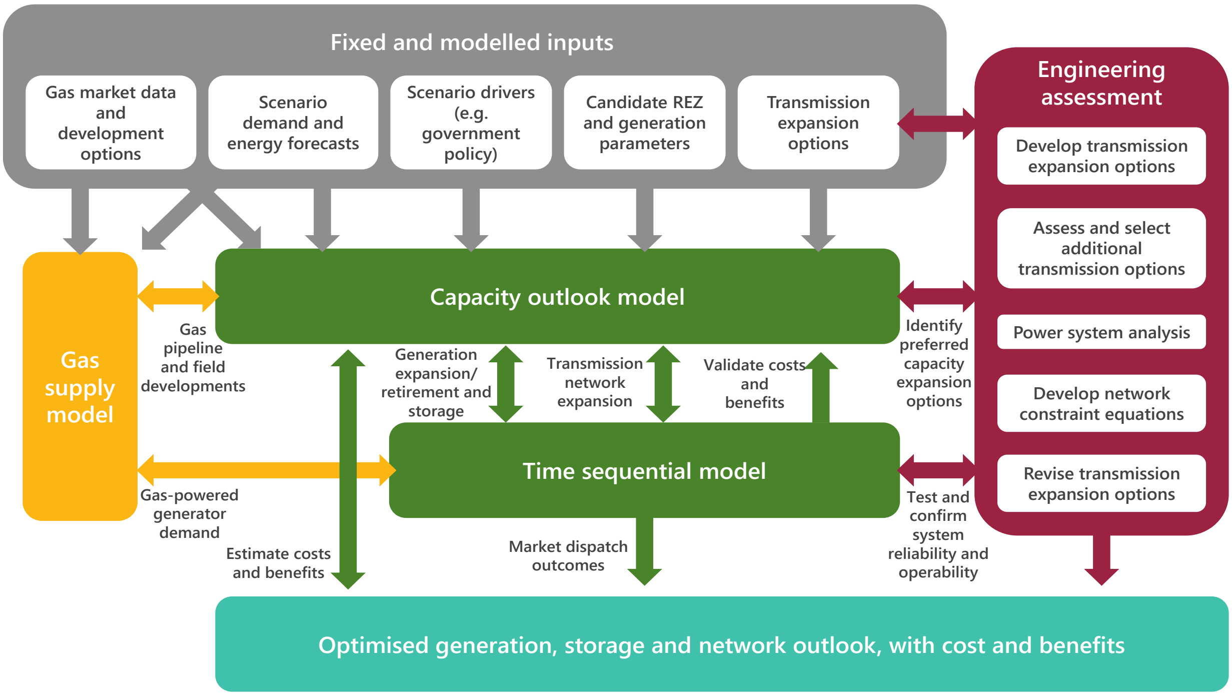
- The **capacity outlook model** projects the generation and transmission build and their dispatch outcomes in each scenario, seeking to optimise capital and operational costs.
- The **time-sequential model** then optimises electricity dispatch for every hourly or half-hourly interval.
- The **engineering assessment** tests and validates the capacity outlook and time-sequential outcomes using power system security assessments to ensure that investments are aligned and robust.
- The **gas supply model** may then validate any assumptions on gas pipeline and field developments.

[29] At https://www.aemo.com.au/-/media/files/major-publications/isp/2021/2021-isp-methodology.pdf?la=en.

[30] See https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-inputs-assumptions-and-scenarios-report.pdf?la=en.

- Finally, the **cost-benefit analyses** test each individual scenario and development plan, to determine the ODP and test its robustness (see Part C).

Figure 10 Overview of ISP modelling methodology



The results of this modelling process, further detailed in the *ISP Methodology*, are given in Part B (ISP Development Opportunities) and Part C (the Optimal Development Path) below.

Part B
ISP Development Opportunities

AEMO has comprehensively modelled each of the scenarios introduced in Part A, in line with the *ISP Methodology* and in consultation with NEM stakeholders.

The ISP has found that the NEM must triple its overall generation and storage capacity if it is to meet the economy's electricity needs in the most likely scenario. Today, NEM installed capacity of nearly 60 gigawatts (GW) delivers approximately 180 TWh of electricity to industry and homes per year. In *Step Change*, utility-scale generation and storage capacity would need to grow to 173 GW and deliver 320 TWh per year to customers by 2050 to cater for their existing loads and replace the gas, petrol and other fuels currently consumed by much of our transport, industry, office and domestic use.

That growth is needed despite significant investment by consumers in distributed energy and energy efficiency. The needs of any hydrogen production associated with export would be *additional* to this growth and result in an eight-fold increase in capacity being required to meet the assumed scale of opportunity in *Hydrogen Superpower.*

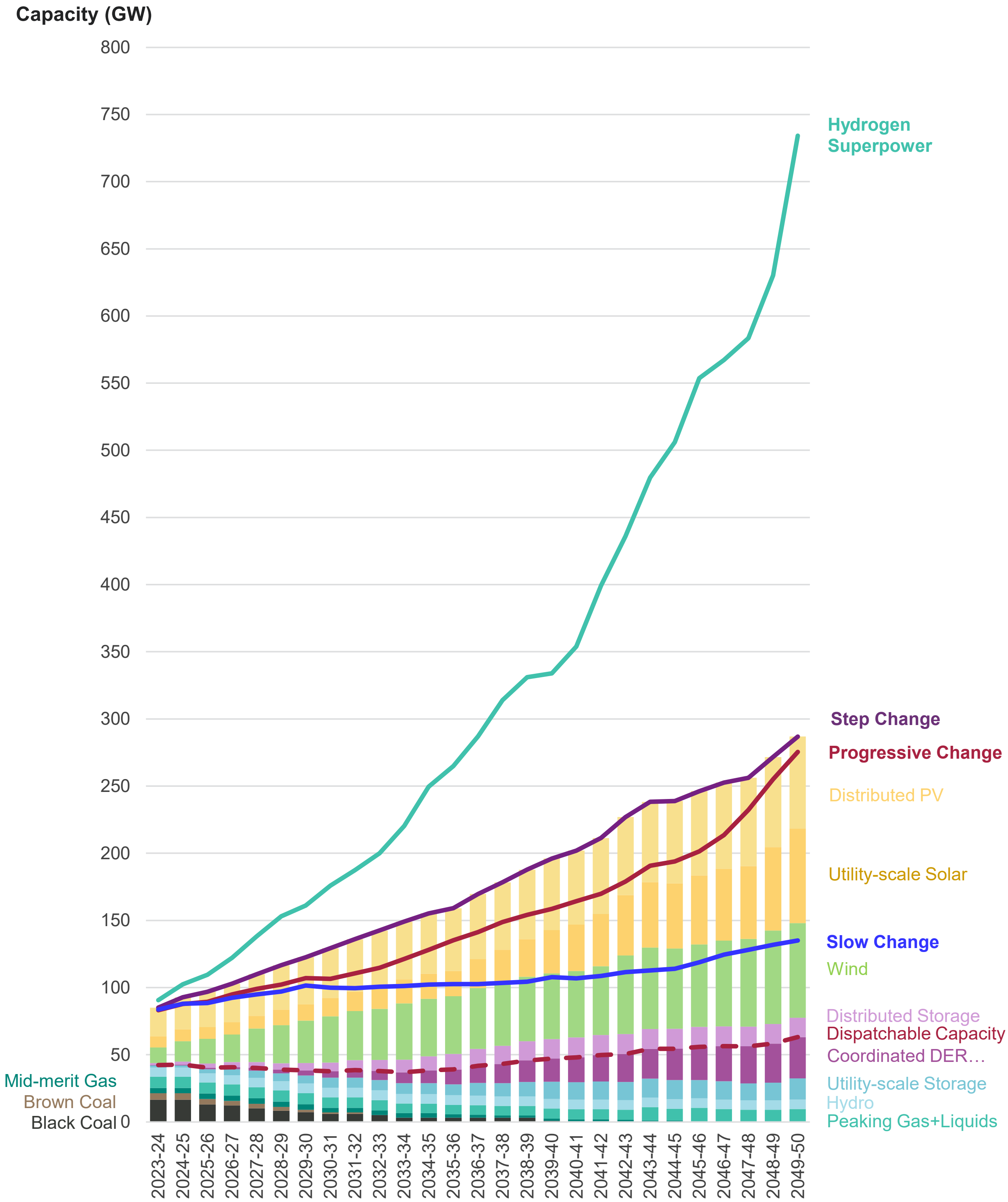
This Part B details how the NEM is forecast to deliver those needs.

- **Section 3 – conversion to renewable generation**. The ISP forecasts that VRE capacity will increase nine-fold by 2050, from 16 GW currently[31] to 141 GW in *Step Change*. That is over a doubling of capacity every decade. Additionally, distributed PV is forecast to increase from 15 GW to 69 GW over the same period.
- **Section 4 – storage and services to support renewable generation.** To firm that VRE and distributed PV, 63 GW of firm dispatchable capacity and additional power system security services will be needed by 2050.

These resources are the ISP development opportunities that form part of the ISP's ODP (see Figure 11). The other part of the ODP, the actionable and future ISP projects, are set out in Part C.

[31] Data is as of May 2022, AEMO Generation Information Page, at https://www.aemo.com.au/energy-systems/electricity/nationalelectricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information. Definitions of committed and anticipated are included in each Generation Information update.

Figure 11 Development opportunities to 2050 in *Step Change*, and compared to total capacity required in *Progressive Change* and *Hydrogen Superpower*



3 Renewable energy capacity needed to achieve net zero emissions

The shift to renewables is already accelerating. On a per capita basis, in 2018-19 Australia added over four to five times the solar and wind generation of any of the European Union, the USA, Japan or China[32], building to today's 16 GW of VRE. Records for instantaneous renewable penetration (including hydro generation and distributed PV) were broken time and again in 2021.

However, the pace is forecast to accelerate further. Since the 2020 ISP, Australian governments have strengthened their emission reduction targets and almost all industrial sectors have clarified their intent to achieve net zero emissions by 2050. Their confidence is rising in the viability of electric alternatives in transportation, manufacturing and mining. At the same time, coal-fired generation is withdrawing faster than anticipated, so that investment in utility-scale generation and storage must accelerate to replace it.

Today, the NEM delivers approximately 180 TWh of electricity to industry and homes per year. The NEM would need to nearly double that by 2050 to serve the electrification of our transport, industry, office and homes, replacing gas, petrol and other fuels.

This Section 3 details the development opportunities needed to accelerate this electrification of the economy, replace coal-fired generation, and provide electricity consumers with the lowest-cost supply. In the most likely *Step Change* scenario:

- The renewable share of total annual generation would rise from approximately 28% in 2020-21 to 83% in 2030-31 (consistent with the Commonwealth Government's policy), to 96% by 2040, and 98% by 2050.
- 69 GW of distributed PV would deliver about one-third of renewable capacity by 2050, with 54 GW of new capacity increasing the current 15 GW capacity nearly five-fold.
- 141 GW of VRE would deliver two-thirds of renewable capacity by 2050, with over 125 GW of new capacity, increasing the current 16 GW capacity almost nine-fold.
- The VRE capacity is best developed in REZs that coordinate network and renewable investment and foster a more holistic approach to regional employment, economic opportunity and community participation.
- Power system development is planned on the basis of efficient operation and dispatch of renewable generation resulting in some curtailment of generation where it is not economic to build transmission and storage to deliver all available electrons at all locations at all times (see Section 3.5).

This transformation of the NEM's generation fleet is fast in both historical and global terms, making it very challenging to achieve from each of a technical, economic and social perspective. However, Australia is uniquely rich in renewable resources relative to global peers, with the financial and institutional capacity to exploit them, offering the opportunity to export renewable energy in large quantities, including in the form of hydrogen. To reach Australia's full storage and export potential (the *Hydrogen Superpower* scenario), the NEM would be called on to deliver eight times its current energy delivery, compared to double in *Step Change* (without the export of energy).

[32] Blakers et al. "Pathway to 100% Renewable Energy", *IEEE Journal of Photovoltaics,* Volume: 9, Issue 6, November. 2019.

3.1 Nearly five times today's distributed energy resources

DER describes consumer-owned devices that can generate or store electricity as individual units and, increasingly in future, may have the 'smarts' to actively manage energy demand. This includes small-scale embedded generation such as residential and commercial rooftop PV systems (less than 100 kilowatts [kW]), PV non-scheduled generation (NSG, up to 30 megawatts [MW]), distributed battery storage, VPPs and EVs.

Today, ~30% of detached homes in the NEM have rooftop PV, their ~15 GW of aggregate capacity meeting their owners' energy needs and exporting surplus back into the grid. By 2032 in the *Step Change* scenario, over half of the homes in the NEM would do so, rising to 65% with 69 GW capacity by 2050. If it is assumed this can all export any surplus to the grid, their 93 TWh of electricity would meet nearly one fifth of the NEM's total underlying demand.

The growth in distributed PV is radically influencing the NEM operational demand[33] profile, with maximum demand now occurring near sunset in most regions, and minimum demand rapidly declining. New sources of dispatchable capacity and critical system services will be required to complement these new resources: see Section 4.

Supporting rooftop PV, behind-the-meter domestic and commercial batteries are expected to grow strongly in the late 2020s and early 2030s as costs decline, with most domestic systems complemented by battery energy storage by 2050.

EV ownership is also expected to surge from the late 2020s, driven by falling costs, greater model choice and availability, and more charging infrastructure. By 2050, between 92% (*Progressive Change*) and 99% (*Step Change*) of all vehicles are expected to be battery EVs.

The integration of DER, including EVs, into the NEM will depend on how well the interface with the energy system is planned, and the effectiveness of economic incentives, technology and communication standards, and customer preferences. The ISP assumes an increasing level of coordination of distributed storage with system and market requirements, potentially via VPPs or alternative, yet to be finalised, market or policy arrangements. This will require increased engagement between consumers, retailers, networks and other market participants: see Section 7.5.

3.2 Nine times today's utility-scale variable renewables

In the most likely *Step Change* scenario, the ISP forecasts the need for over 125 GW of additional VRE by 2050, to meet demand as coal-fired generation withdraws. This means maintaining the current record rate of VRE development every year for the decade to nearly treble the existing 16 GW of VRE by 2030 – and then doubling that capacity by 2040, and again by 2050.

In *Hydrogen Superpower*, the scale of development can only be described as monumental. For Australia to become a renewable energy superpower, as assumed in this scenario, the NEM would need approximately 269 GW of wind and approximately 278 GW of solar – 34 times its current capacity of VRE. This would

[33] Operational demand refers to electricity supplied from the grid and thus excludes any self-generation. The full definition (including exceptions) is available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Dispatch/Policy_and_Process/Demand-terms-in-EMMS-Data-Model.pdf.

expand the total generation capacity of the NEM more than eight-fold (rather than over two-fold for the more likely *Step Change* and *Progressive Change* scenarios).

3.2.1 A mix of solar and wind is required

Resource diversity across the NEM helps reduce the need for firming and dispatchable resources, and reduce the volatility associated with a weather-powered energy system. Both geographic spread (see below) and a mix of wind and solar technologies provide that diversity.

Wind and solar offer complementary daily and seasonal profiles. Taking distributed PV into account, they will have almost equal shares of NEM generation by 2050, though after different trajectories: see Figure 12 and Figure 13 below. Through the 2020s, more wind capacity would complement the existing strong uptake of distributed PV, so that wind would represent approximately 85% of all additional VRE projects in *Step Change* (that is, beyond existing, committed and anticipated projects).

Utility-scale solar would accelerate again once there is enough storage and network investment. Although solar VRE is relatively low-cost, it needs more storage to time-shift its midday generation peaks to the morning and evening demand peaks, particularly given the abundance of distributed PV generation. By 2050, newly installed utility-scale solar would make up about half of newly installed VRE capacity in *Step Change*.

Offshore wind has great potential due to resource quality, possible lower social licence hurdles, and proximity to major load centres via strong transmission corridors. However, this emerging technology is currently a higher cost solution than on-shore options. The cost of offshore wind is reducing, and further cost reductions could see it feature more prominently in future ISPs, particularly if it secures direct third-party support or land use considerations limit onshore development.

Figure 12 Growth and share of utility-scale solar and wind capacity, all scenarios

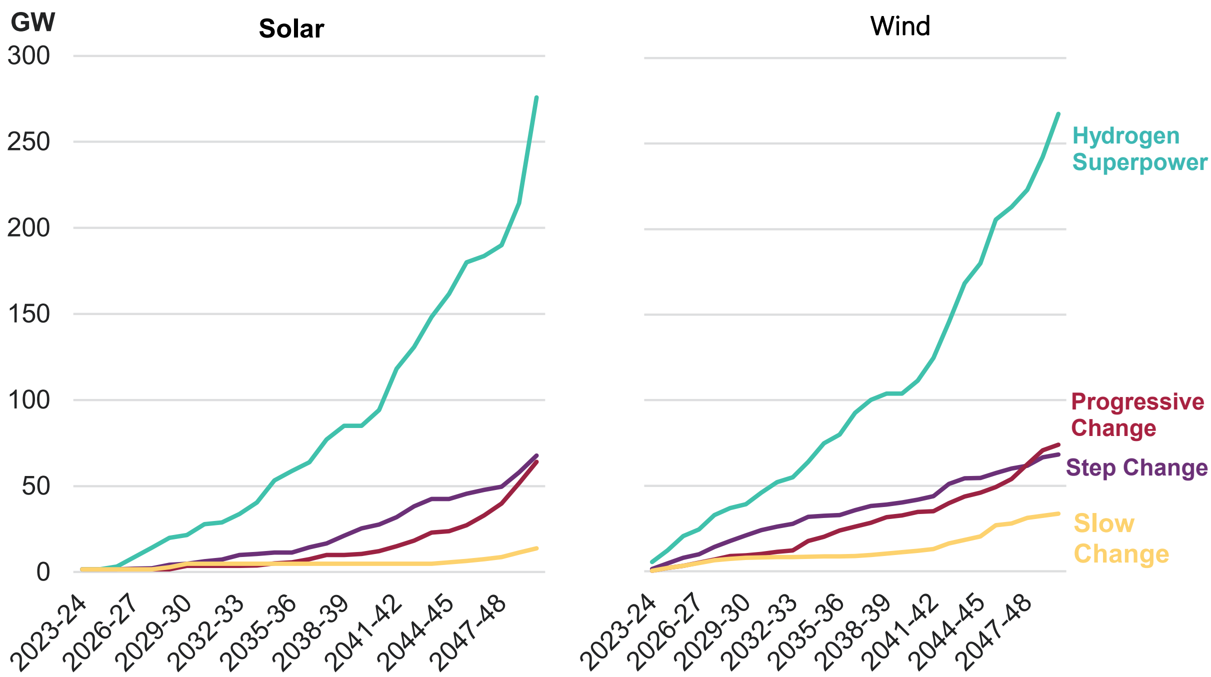
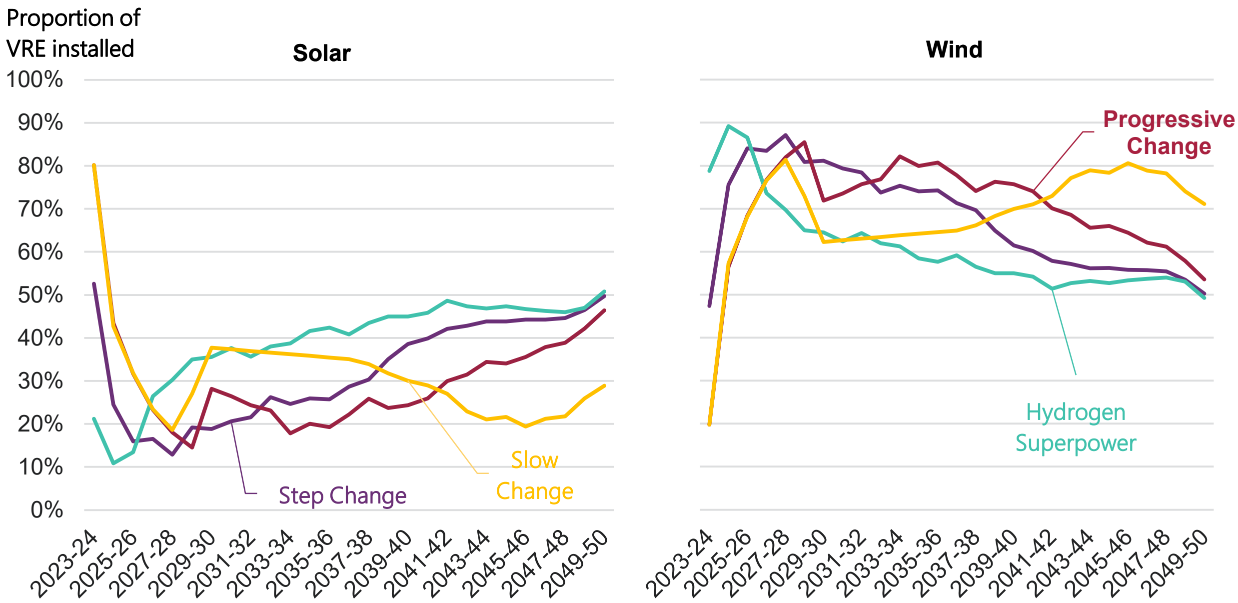


Figure 13 Proportional cumulative development of new utility-scale renewable capacity



3.2.2 The value of geographic diversity and strong interconnection

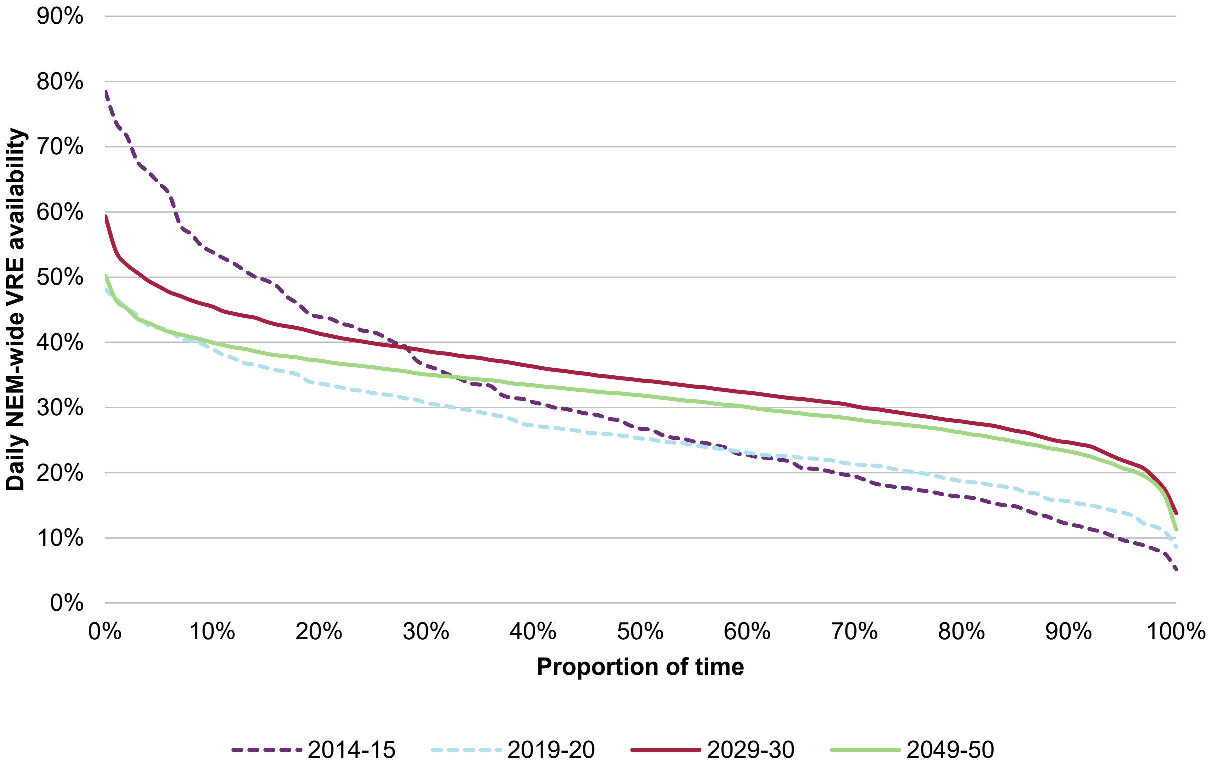
Developing VRE in diverse locations improves the operability of the grid under all weather conditions, bringing multiple benefits. Assuming it can be connected efficiently across the NEM, diversity reduces the variability of renewable generation, the frequency of low aggregate output, and the vulnerability to localised weather events. This reduces the need for investment in other forms of generation and storage which would increase the overall cost.

The impact of a diverse renewable resource, both geographically and technically, is show in Figure 14.

Back in 2014-15 (the line with the steepest slope), the NEM-wide availability of VRE would reach above 20% only 65-70% of the time, since there were limited installations in limited places. By 2029-30, that level would be reached over 95% of the time. The figure indicates that the variability of renewable energy availability reduces as VRE penetration increases, with significant improvements projected with the growth in renewable energy technology and geographic diversity.

Appendix 4 further explores the future resilience of the power system to renewable generation intermittency.

Figure 14 Daily NEM-wide actual and projected VRE availability



3.3 Renewable energy zones for new VRE

There is already 16 GW of utility-scale VRE installed in the NEM, and approximately another 6 GW is expected to be operational over the next few years, as either committed or anticipated projects[34].

Much of this VRE will be built in REZs that seek to coordinate network and renewable investment and foster a more holistic approach to regional employment, economic opportunity and community participation. If well planned and supported by appropriate social licence, REZs can improve grid reliability and security, minimise community, environmental and aesthetic impacts, adhere to relevant design standards and regulatory requirements, and offer flexibility and scalability to address the future needs of the power system. To fulfil that potential, REZs will need to establish strong community support, quality renewable resources and network capacity. REZs may then materially reduce costs and risks for VRE investors, ultimately for the benefit of consumers, by:

- reducing transmission and connection costs and risks,
- sharing costs and risks across multiple connecting parties,
- co-locating and optimising system support infrastructure and weather observation stations, and
- promoting regional expertise and employment at scale.

[34] Data is as of May 2022, AEMO Generation Information Page, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information. Definitions of committed and anticipated are included in each Generation Information update.

Appendix 3 details each of the 41 REZs, including six offshore wind zones (OWZs), considered in the ISP. In *Step Change*, the following developments, also highlighted in Figure 15, are projected above what is already existing, committed or anticipated in REZs within each region over the next 10 to 20 years:

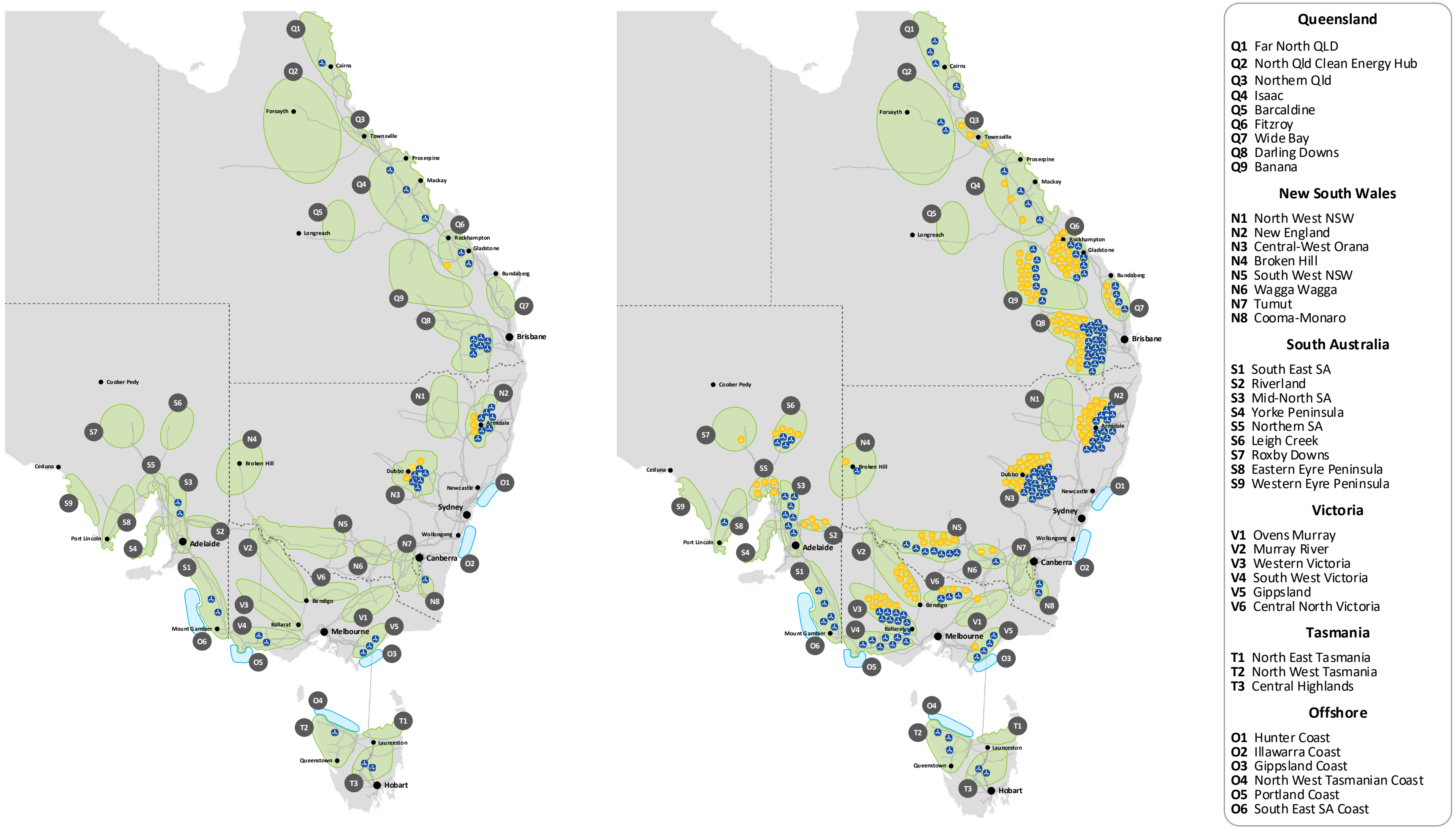
- **40 GW new VRE in New South Wales by 2050.** The Central-West Orana REZ would install 2.1 GW by 2026-27, increasing to 4.6 GW by 2030 and 7.7 GW by 2040. The New England REZ would similarly install 5 GW by 2030 increasing to 10.4 GW by 2040. This development is consistent with the minimum development requirements of the New South Wales Roadmap to deliver at least 33,600 GWh p.a. by the end of 2029[35].
- **50 GW new VRE in Queensland by 2050.** Darling Downs, Far North Queensland, Isaac and Fitzroy REZs would all take advantage of spare network capacity to together install approximately 7.1 GW by 2030. Following that, Darling Downs and Fitzroy would see greater development to add more than 5.6 and 8.8 GW each between 2030 and 2040.
- **15.5 GW new VRE in South Australia by 2050**, taking advantage of the Project EnergyConnect interconnector. REZs with high wind quality would see the earliest development: South East South Australia with an additional 0.76 GW by 2030 and 1.2 GW by 2040, and Mid-North South Australia installing 1.15 GW by 2030, reaching 2.9 GW by 2040.
- **2.5 GW new wind in Tasmania by 2050**, provided Marinus Link is built. Of that, approximately 1.1 GW is projected to be installed in the Central Highlands REZ, and 1.3 GW in the North West Tasmania REZ. No further VRE capacity is forecast, and without significant cost reductions, there is no offshore wind projected in Tasmania in any scenario.
- **23 GW new VRE in Victoria by 2050**, with only 2.5 GW above what is already existing, committed or anticipated forecast to be required by 2030, in the South West Victoria and Gippsland REZs utilising the existing spare network. Without significant cost reductions, no offshore wind development is projected in Victoria in any scenario.

A new REZ Design Report process[36] has been introduced into the ISP process under the NER to help ensure that the REZs meet their technical, social and economic requirements. There are no REZ Design Reports being triggered in this 2022 ISP, as REZ frameworks are still being defined in some jurisdictions. Assuming the relevant government support, AEMO may trigger a REZ Design Report either in or between ISPs: see Section 7.2.2. While some developments may connect efficiently to existing transmission capacity, many will need stronger technical coordination for their connection, greater two-way engagement with their local communities, and strengthening resource and employment supply chains.

[35] See the NSW Electricity Infrastructure Roadmap, at https://www.energy.nsw.gov.au/government-and-regulation/electricity-infrastructure-roadmap/about-roadmap#-renewable-energy-zones-.

[36] See NER 5.24

Figure 15 REZ development in the *Step Change* scenario – 2029-30 (left) and 2049-50 (right)



† AEMO has updated the REZ boundaries for N5 aligned with geographical area of the SWNSW REZ in Schedule 1 of the draft REZ declaration, available at https://www.energy.nsw.gov.au/sites/default/files/2022-03/Draft%20South-West%20REZ%20Declaration.pdf. AEMO will update all relevant parameters in the 2024 ISP.
‡ EnergyCo is in the early stages of planning for two new REZs in the Hunter-Central Coast and Illawarra regions of New South Wales, as set out under the New South Wales Electricity Infrastructure Act 2020. These REZs are not shown because they are not yet geographically defined.

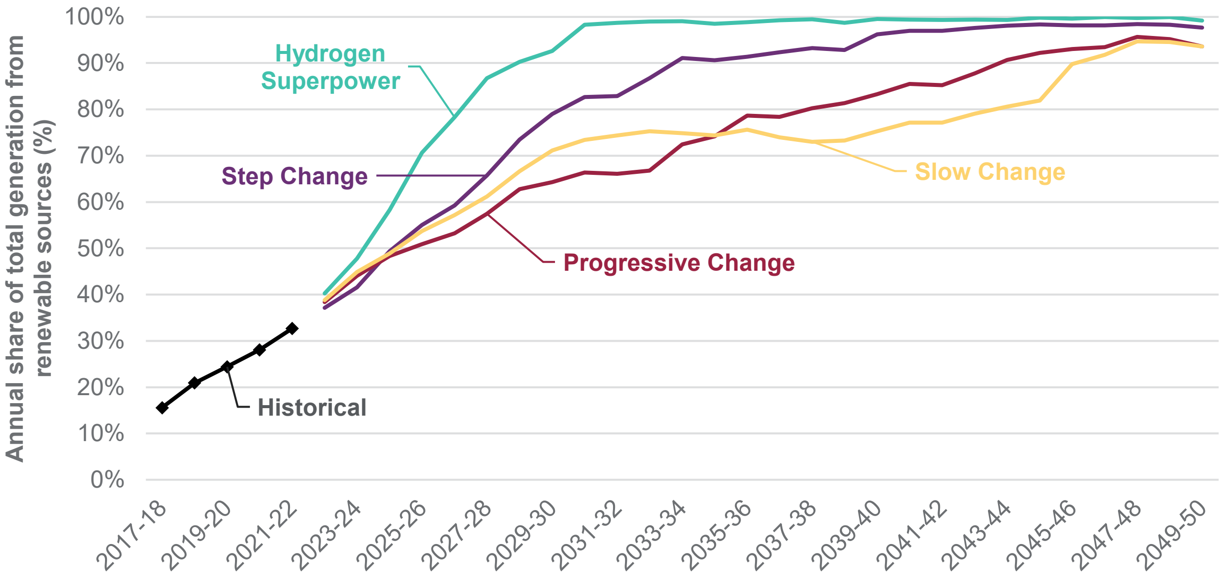
3.4 Rising renewable shares of annual and instantaneous dispatch

The NEM is continuing its transformation towards higher levels of renewable energy output, including a world-leading penetration of VRE in growing parts of the network. This requires significant power system engineering to accommodate rising shares of both annual and instantaneous dispatch.

The share of renewable energy as a proportion of annual generation is shown in Figure 16. In *Step Change*, the renewable share of total annual generation will rise from approximately 32% in 2021-22 to 83% in 2030-31, to 96% by 2040, and to 98% by 2050. In the 2020s alone, half of all NEM generation will be produced from renewable resources.

By the mid-2040s, electricity supply is expected to be generated almost exclusively from renewable resources, with energy storages helping to manage their seasonality and intermittency, and peaking gas-fired generation providing firming support. These periods of high renewable potential will occur most at times of low demand initially, and then become more frequent as more VRE is installed.

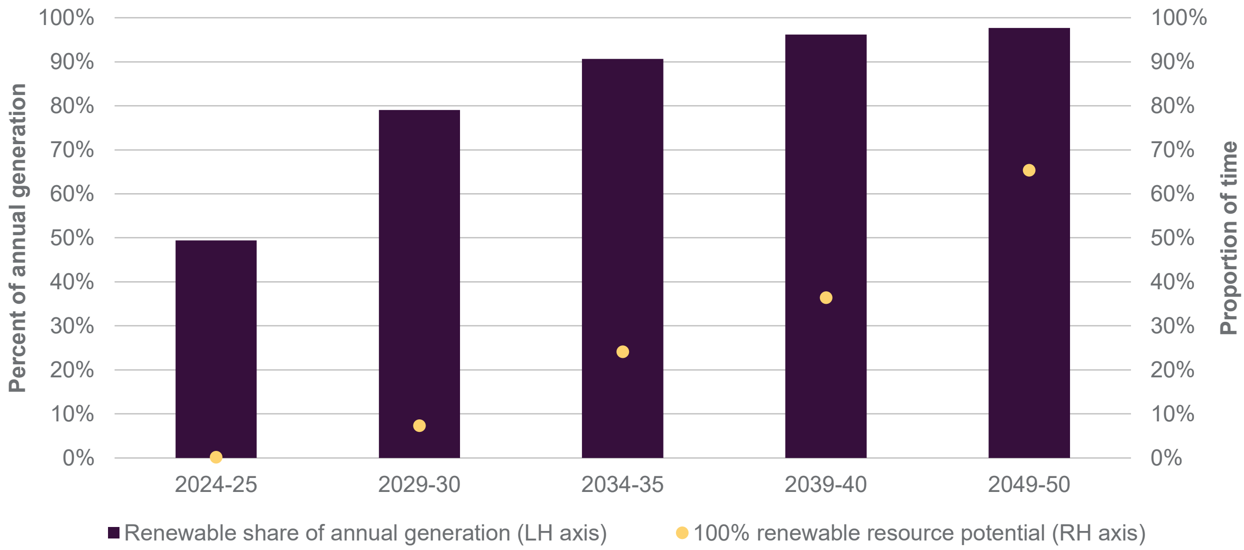
Figure 16 Annual share of total generation from renewable sources (each scenario, optimal development path)



As the share of generation from renewables increases at annual level, there will be more periods where the total NEM generation could be sourced from the renewables potential available. In the most likely *Step Change* scenario, there will be enough potential renewable resources to meet 100% of grid demand, for a small number of dispatch periods, as early as 2025. By 2040, the NEM's potential renewable resources could meet 100% of demand approximately 36% of the time – and 65% by 2050 (see Figure 17).

However, AEMO must engineer the power system to operate securely as the "instantaneous renewable penetration" reaches 100% (i.e. periods when renewables provide *all* of the energy actually dispatched). The share of potential resource that is actually dispatched at any time depends on a range of market factors. Instantaneous renewable penetration peaks in summer, has been rising at 6-7% each year, and reached a record 61.8% on 15 November 2021. As the power system approaches 100% instantaneous renewable penetration, AEMO must be able to securely dispatch the available renewable resources, using storage to help absorb local supply excesses. AEMO and the NEM stakeholders are therefore collaborating towards a power system capable of operating with 100% instantaneous renewable penetration by 2025: see Section 7.6.

Figure 17 NEM annual share of renewable generation and 100% resource potential, 2025-50, *Step Change* scenario



3.5 Curtailment of VRE will sometimes be efficient

The ISP modelling confirms that, rather than build network and storage to capture every last watt of energy, it is sometimes more efficient to curtail[37] or spill[38] some generation. This may occur when there are system security or other operability constraints in the network, or there is simply over-abundant renewable energy available.

Assuming there is sufficient transmission, most of the spill identified in ISP modelling would be when utility-scale wind and solar become direct competitors for dispatch, rather than pricing out fossil fuel generation. At these times there is simply not enough operational demand to utilise all available renewable resources. Adding more storage to soak up the surplus supply is unlikely to be economically efficient because, with so much annual renewable generation, there is little marginal value in shifting VRE to other times in the day, month or year.

Curtailment or spill of VRE generation is forecast to occur when there is higher solar generation: during daylight hours and during spring and summer. Accepting this constraint while building enough VRE to meet the energy needs of winter is likely to be more efficient, on estimated technology costs, than building less VRE but more seasonal storage. The economics also demonstrate that overbuilding VRE generation is more efficient than just matching generation with requirements, similar to that for other forms of generation based on average capacity factors.

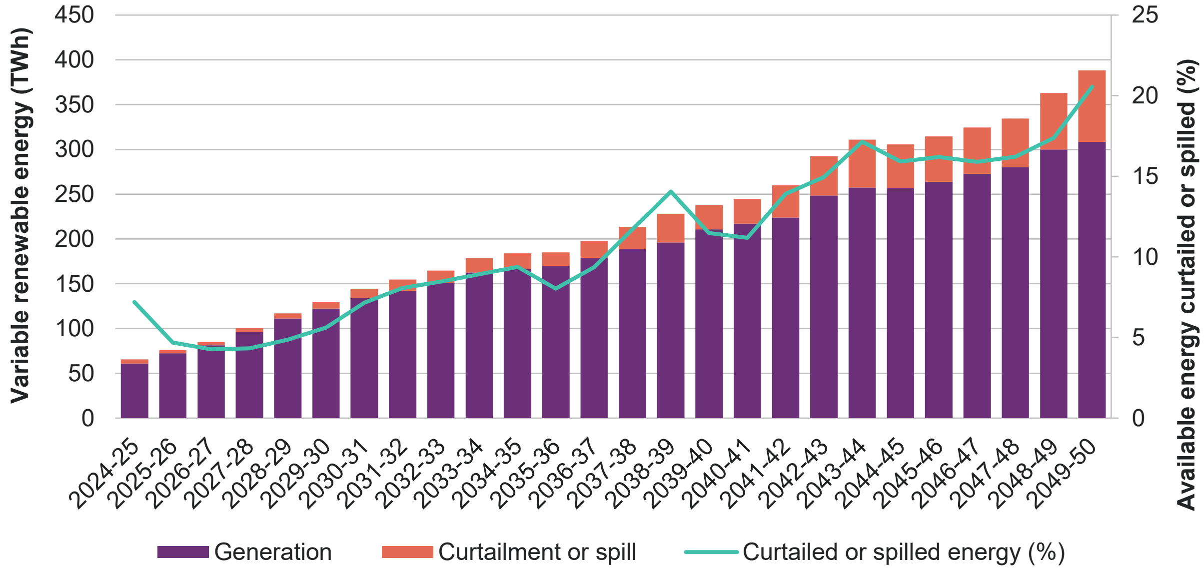
By 2050, the efficient level of curtailed or spilled generation in *Step Change* increases to approximately 20% of total available VRE output: see Figure 18. Market reforms are being developed by the Energy Security

[37] Curtailment happens when generation is constrained down or off due to operational limits.

[38] Economic spill happens when generation reduces output due to market price.

Board (ESB)[39], with the aim of ensuring that incentives are in place for investors to develop an optimal level of VRE capacity.

Figure 18 Curtailment and spill of NEM variable renewable generation, *Step Change*



[39] ESB Post 2025 Electricity Market Design. Available at https://esb-post2025-market-design.aemc.gov.au/.

4 Dispatchable capacity needed to firm the renewable supply

Section 3 detailed the renewable resources needed to meet consumer demand efficiently as coal- and gas-fired generation retires, at the same time as industry and households switch to electricity from petrol and gas power.

This transformation poses significant operability challenges in retaining the levels of reliability and security that consumers rightly expect from their power system. Significant investment in the NEM is needed to treble the firming capacity that can respond to dispatch signals, along with efficient network investment. Wholesale demand response and other flexible loads will also help manage peak loads and troughs, and reduce reliance on more capital-intensive responses.

The ISP seeks to find the most cost-efficient balance between investment in network transmission (see Part C) and in dispatchable capacity to complement renewable generation development. The less transmission capacity there is, the more dispatchable capacity is needed, and vice versa.

This Section 4 details the development opportunities in the NEM to meet those challenges, as part of the ODP. It discusses the following projected shifts:

- the withdrawal of 23 GW of coal capacity, 14 GW of it by 2030 in the *Step Change* scenario,
- the development of 47 GW of new battery and hydro storage (distributed and utility-scale), able to respond to a dispatch signal to help firm the renewables,
- the need for approximately 10 GW of gas-fired generation for peak loads and firming, particularly during long ‘dark and still’ weather periods,
- the increased value of wholesale demand response and other flexible loads to take advantage of renewable energy oversupply, and minimise disruption during undersupply,
- the increased need for network to shift electricity from where it is produced to where it is needed, maximise the value of geographic diversity and efficiently share resources across the NEM, and
- the increased need to strengthen power system services as the system rapidly approaches 100% instantaneous renewable energy potential.

The detailed analysis underpinning this section is set out in Appendix 4 (System Operability).

4.1 Coal-fired generation retiring faster than announced, with 60% of capacity withdrawn by 2030

***Step Change* forecasts the withdrawal of 14 GW of the 23 GW current coal capacity in the NEM by 2030, while coal plant owners have yet announced only 8.4 GW in withdrawals.**

The sector is undergoing a more rapid change than has been previously expected, and some coal-fired generators have brought forward their announced retirements since the 2020 ISP[40]. Their decisions remain necessarily uncertain, as they grapple with operating dynamics in the face of cheap renewable generation, their own competitive strategies, changes in government policy or regulation, plant conditions, maintenance and remediation costs, and the wishes of local communities (to either close or remain open). The gas and coal price volatility hitting global energy markets from the first half of 2022 places additional pressure on the profitability of Australia's generators, raising uncertainty – and the possibility of unexpected early closures.

If closures can be coordinated with adequate notice, then technical and market challenges may be managed. If they are not, the risk of price and reliability impacts on consumers quickly rises. Given these uncertainties, prudent planning through the ISP highlights the need for significant investments in dispatchable renewable resources, transmission and power system services and illustrates the additional resilience value of bringing forward some projects to hedge against these risks.

The currently announced closure timings suggest that only 8.4 GW of the current 23 GW of coal capacity will withdraw by 2030. This includes the announcement that Eraring Power Station may potentially close by 2025. The Draft 2022 ISP identified a collection of accelerated coal retirements, with *Step Change* providing a retirement trajectory broadly aligned with announced coal retirements in the near term, including the Eraring closure, however another 5.8 GW of closures by 2030 are forecast.

The ISP forecasts faster withdrawals across all scenarios:

- In *Step Change*, modelling indicates 14 GW of coal-fired generation is likely to withdraw by 2030 to meet tighter carbon budgets for the sector. All coal capacity could close as early as 2040.
- In *Progressive Change*, modelling indicates coal-fired generation is likely to withdraw faster than current announcements, although equivalent by 2030. From then, competitive operating conditions drive regular withdrawals slightly earlier than currently reported by participants, until only 2 GW capacity remains by 2050, representing less than 1% of the total generation capacity.
- In *Hydrogen Superpower*, modelling indicates 20 GW of the current 23 GW of installed capacity is likely to withdraw by 2030, in response to the ambitious decarbonisation objectives, and all coal (as well as mid-merit gas) would retire by 2050. This is in spite of the additional increase in demand for electricity for hydrogen production.
- In *Slow Change*, modelling indicates that 10 GW of coal-fired generation is likely to withdraw by 2030, even more than in *Progressive Change*. This is because reduced electricity consumption and the same investment in VRE to meet renewable energy policies result in lower daytime residual demand (operational demand met by generators other than VRE), and so less need for dispatchable coal. By 2050, only 2 GW of coal capacity is expected to remain operational (as forecast in *Progressive Change*).

These retirements are shown in Figure 19 below. The retiring coal will require significant scale and diversity of storages and other dispatchable generation to firm VRE: see Section 4.2 below.

Of the coal types, higher emission brown coal-fired generation is likely to be retired ahead of black coal-fired generation, to help meet the faster emission reduction ambitions of *Step Change* and *Hydrogen Superpower*. However, the efficient pathway to a zero-coal grid would likely progressively retire power stations across more than one region at a time so closures can be managed reliably and securely. Figure 20 sets out that modelled

[40] Yallourn Power Station (by four years, to 2028), Eraring Power Station (by up to seven years, to 2025), Mount Piper Power Station (by two years, to 2040). Bayswater Power Station (by two years, to 2033), Loy Yang A Power Station (by three years, to 2045).

pathway for *Step Change*, highlighting an earlier and diverse retirement schedule than present announcements would suggest.

Figure 19 Forecast coal retirements, all scenarios versus announced retirements

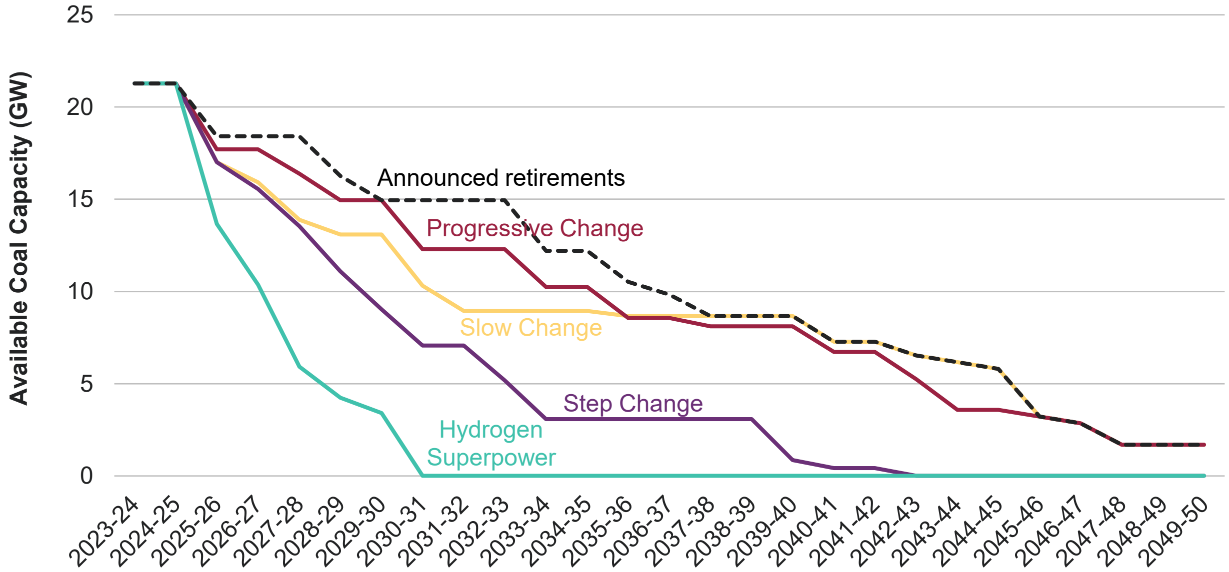
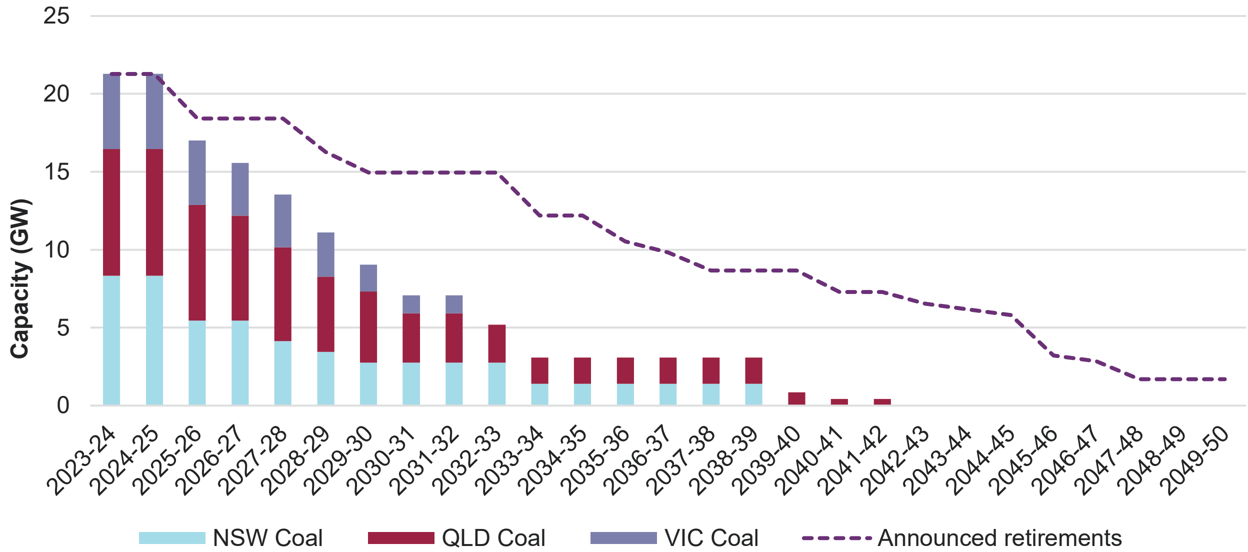


Figure 20 Forecast coal retirements, *Step Change* technology and regional outlook



4.2 Treble the capacity of dispatchable storage, hydro and gas-fired generation to firm renewables

Approximately 46 GW/640 GWh of dispatchable storage capacity, 7 GW of existing dispatchable hydro, and 10 GW of gas-fired generation is needed by 2050 to efficiently operate and firm VRE.

By 2050, the most likely *Step Change* scenario would call for over 60 GW of firming capacity to be in place to respond to a dispatch signal. This may be provided by utility-scale batteries, hydro storage, gas-fired generation, smart behind-the-meter batteries or VPPs and, potentially, vehicle-to-grid (V2G) services from

EVs. The willingness of consumers to lower their consumption during high price periods (referred to as demand-side participation, or DSP) will also have an important role to maintain reliability and avoid involuntary load shedding.

While the system today has approximately 43 GW of firming capacity, 23 GW of this is coal-fired generation. As this coal-fired generation retires, it needs to be replaced with new low-emission firming alternatives. New utility-scale battery and pumped hydro storage, located at appropriate parts of the network, will enable more effective dispatch of clean electricity on demand, increase resilience by shifting energy through time to manage weather variations, and provide critical system security services.

This Section 4.2 considers how:

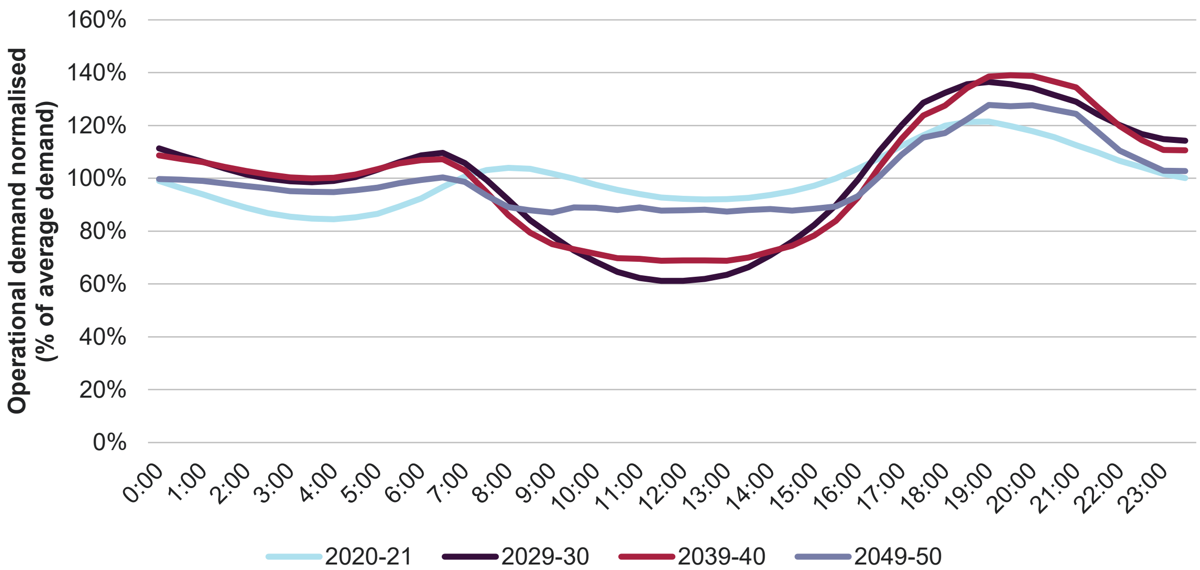
- the NEM's daily operational demand pattern is forecast to change as distributed storage helps soak up excess distributed PV during the day, and reduce peak demands in the evening,
- different storage depths are needed to manage this intra-day pattern, as well as match supply and demand between days and between seasons (with high levels of consumer engagement needed to coordinate DER storages), and
- gas-fired generation will help manage extended periods of low VRE output and peak demands, and also deliver power system services to provide grid security and stability as coal retires.

The average daily operational demand pattern will flatten over time

Energy consumption behaviour will continue to change, driven by continued DER uptake, improving energy efficiency and increasing electrification. As it does, the time-of-day operational demand will change shape, with a gradual flattening of the peaks and troughs.

Figure 21 shows that flattening through the *Step Change* scenario, normalised to remove the effects of rising energy consumption. It shows how average daytime demand will fall to 2030 when the minimum will occur in the middle of the day. This is driven down by the uptake of rooftop PV, but then be driven back up through 2040 to 2050 as other sectors switch to electricity, and more battery systems charge with any excess solar. The evening peak demand then flattens as those battery systems discharge during the evenings.

Figure 21 NEM normalised average time of day operational demand, actual and *Step Change*



Additional insights on consumer demand (not discernible from Figure 21) include:

- An electrified transport fleet may have a strong influence on the shape and location of load. If consumers charge their EVs through the day, encouraged by infrastructure and appropriate financial incentives, they potentially may be able to store excess PV generation (provided the distribution assets are provided to support these mobile demands) and, if aligned with wholesale dispatch, potentially assist in managing the operation of the power system. Conversely, EV charging in the evening will add to the system's evening peaks and may contribute to additional system costs.
- Flexible demand response for EVs and other electric appliances (see below) may assist with flattening the shape of operational demand, helping to reduce the need for new firming capacity[41].
- Electricity demand will increase during winter, due to electric heating in a season with shorter days and weaker solar radiance.
- Maximum demand in winter is still forecast to be lower than in summer for extreme years in most regions, but in more typical years, those regions can expect their maximum demand to fall in winter, representing a shift from historical trends.
- In later years, hydrogen production may operate with some flexibility, as electrolysers may operate more heavily during periods of excess renewable supply.

A range of firm, dispatchable resources is needed to firm VRE

Dispatchable resources are needed to firm renewable energy intermittency through all weather conditions across the NEM. Diversity in those firming resources will become more valuable as renewables become the dominant source of generation. That diversity may be both geographical and technological, including gas-fired generation and energy storage of varying depths.

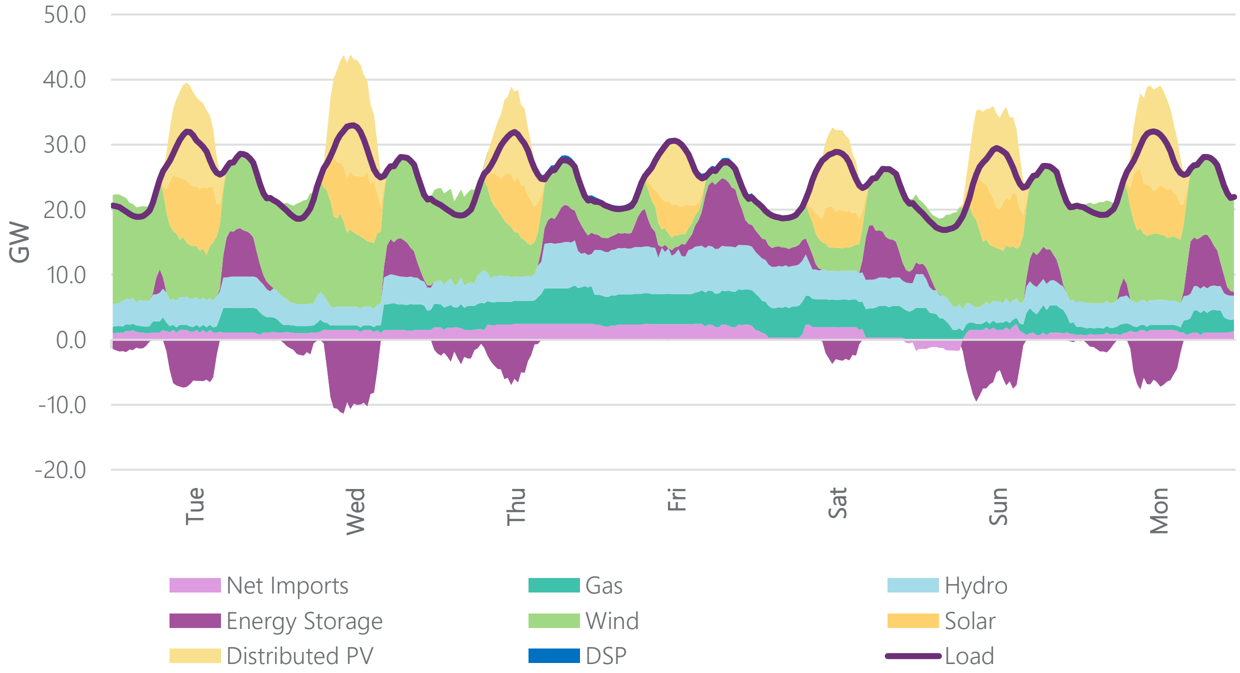
Figure 22 shows how the different generation sources interact to deliver electricity to consumers across New South Wales, Victoria, South Australia and Tasmania through a forecast winter week in July 2040, using a historically observed set of weather conditions. In this sample winter week, weather conditions across regions are calm, cloudy and cool, leading to higher heating loads in the southern regions and limited renewable energy availability. Above 0 on the Y-axis is generation consumed, and below 0 is excess generation stored.

Figure 22 demonstrates the value of technological and geographic diversity in the ISP development opportunities, along with transmission capacity to share resources. In the illustrated week, Queensland and northern New South Wales wind offered reasonable generation, unlike the becalmed sites across the southern mainland and Tasmania. Sunny inland locations in Queensland and New South Wales span a large geographical area such that their utility-scale PV is less likely to be shaded by cloud than the distributed PV in coastal cities.

Queensland consumption and generation is excluded from the chart to showcase the dynamics in the other regions more easily, noting that a reasonable level of both wind and solar generation in Queensland was available to be imported, further highlighting the value of technological and geographical diversity.

[41] To enable the scale of demand response potential assumed in later years in some scenarios, market reforms such as those reported on in Section 4.3 may be necessary, as well as acceptance from consumers.

Figure 22 A week's dispatch outcomes across the NEM (excluding Queensland), *Step Change*, June 2040



On Tuesday and Wednesday in this example, storages absorb abundant renewable energy, particularly during the day when excess solar generation is available. The most severe renewable energy shortfall then runs from Thursday to Saturday, when there is very little wind generation. Storages, hydro and gas-fired generation play a strong firming role during these three days of low renewable energy – even discharging storages throughout the night. Transmission investment helps overcome that shortfall by accessing gas-fired and hydro generation and energy storages across the NEM, including surplus renewable energy from Queensland.

The dispatch outcomes presented in Figure 22 assume that the system operator and generators have sufficient forewarning of these challenging weather conditions. If so, deep storages and hydro reservoirs are more likely to be filled and held in reserve. In reality, weather conditions are more uncertain. Assets like deep energy storage and transmission can increase resource sharing and power system resilience, reducing the impact on consumers of unexpected weather events.

Appendix 4 provides further detail on how the future system might operate under greater uncertainty during such events, as well as case studies of extreme weather that could disrupt key transmission paths. These demonstrate that route diversity in a stronger interconnected system increases resilience to a changing climate.

Different storage types have different, complementary roles

The ISP demonstrates the strong need for storage to complement VRE developments. The NEM will draw on a range of different storage types and depths to manage the daily, weekly, and seasonal balance of energy availability and energy consumption. The box below describes the ISP storage types, used through the rest of this section.

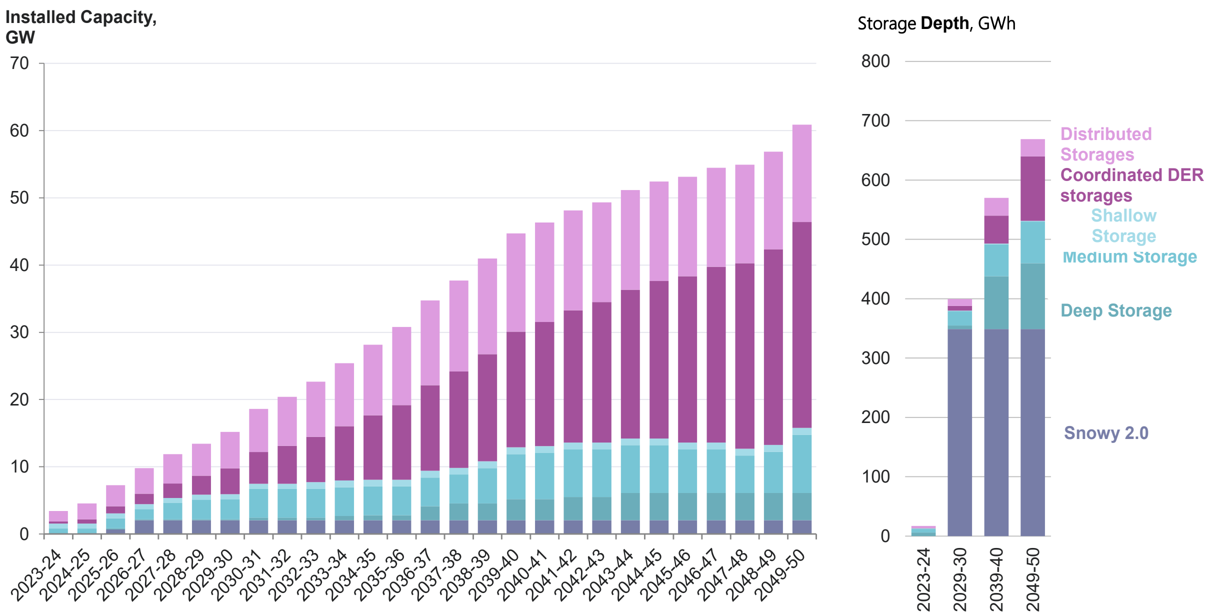
Different types and depths of storage

- **Distributed storage** – includes non-aggregated behind-the-meter battery installations designed to support the customer's own load.
- **Coordinated DER storage** – includes behind-the-meter battery installations that are enabled and coordinated via VPP arrangements. This category also includes EVs with V2G capabilities.
- **Shallow storage** – includes grid-connected energy storage with durations less than four hours. The value of this category of storage is more for capacity, fast ramping and frequency control ancillary services (FCAS, not included in AEMO's modelling) than for its energy value.
- **Medium storage** – includes energy storage with durations between four and 12 hours (inclusive). The value of this category of storage is in its intra-day energy shifting capabilities, driven by the daily shape of energy consumption by consumers, and the diurnal solar generation pattern.
- **Deep storage** – includes energy storage with durations greater than 12 hours. The value of this category of storage is in covering VRE "droughts" (long periods of lower-than-expected VRE availability) and seasonal smoothing of energy over weeks or months.

Medium storage to manage daily variations in solar and wind output

Figure 23 shows the forecast need for each of the storage types through the *Step Change* scenario.

Figure 23 Forecast of MW storage capacity (left) and energy storage capacity (right), *Step Change*



The most obvious feature on the left-hand chart is the projected growth of coordinated DER (see next section) and other distributed storage. This will typically help customers lower their evening peak demand. Given this, the most pressing utility-scale need in the next decade (beyond what is already committed) is for storage of 4-to-12 hours' duration to manage stronger daily variations in solar and wind output, and to meet consumer demand also during more extreme days as coal capacity declines. This is visible in the left-hand figure, with most utility-scale storage (aqua-coloured bands) shown at medium depth. If the distributed storage uptake is slower than assumed, then more utility-scale shallow storage would be needed instead.

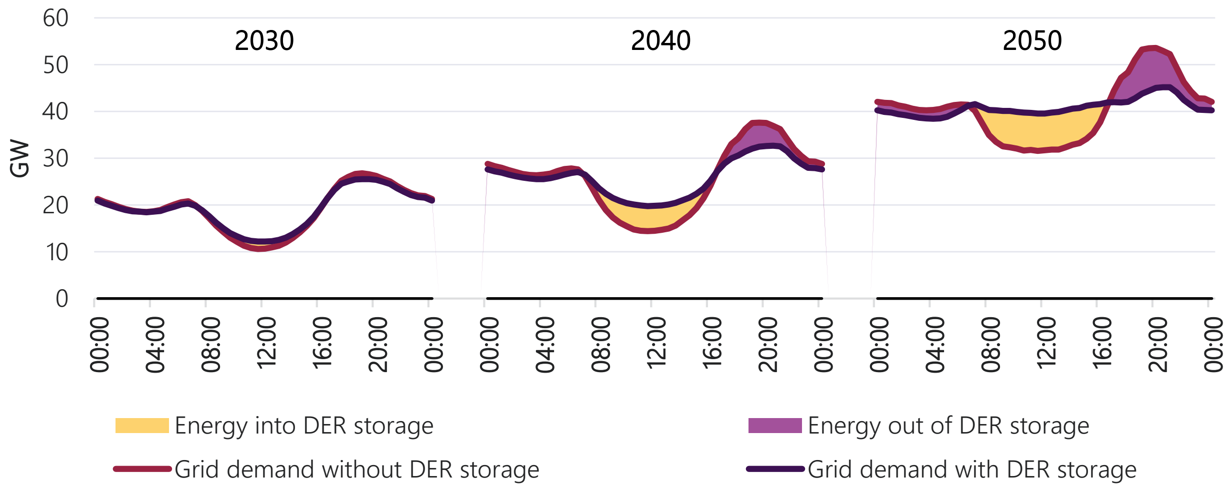
The need for medium-depth storage includes 2 GW of storage that can be dispatched for at least eight hours, needed by the end of 2029 to help meet the objectives of the New South Wales Roadmap. The 2021 IIO Report[42] recognises the supply chain and other issues that may delay delivery of these projects, and allows for contingencies. Such delivery risks are assessed for their impact on transmission projects when selecting the ODP: see Section 6. There may be opportunities for further medium and deep storage projects, for example pumped hydro sites, in locations that allow for lower cost development.

Distributed storage to complement daily PV generation

As shown in Figure 23, distributed storage including coordinated VPPs is forecast to represent almost three-quarters of dispatchable capacity (in MW terms) in *Step Change* by 2050, reducing the need for shallow storage at utility scale[43]. This coordinated DER storage and distributed storage absorbs day-time solar oversupply and discharges during the evening peaks, smoothing out much of the daily curve for NEM operational demand.

In Figure 24 below, the red line represents grid demand without the DER storage. The yellow shape represents excess PV generation through the daylight hours. The DER storage captures that excess, then discharges it after 4:00 pm during the evening peak. The dark blue line represents the resultant grid demand. DER storage operating in this manner significantly reduces the need for traditional generation and firming sources such as coal and gas, as well as utility-scale shallow storage.

Figure 24 Average time of day profile – impact of co-ordinated DER and distributed storage, *Step Change*



Distributed storage that is well coordinated and operated in orchestration with system requirements and market signals, for example through VPPs, and through the active management of consumer devices (using smart, cloud-connected and rule-based devices), provides the opportunity for offsetting the amount of firming needed in a highly renewable system. This in turn depends on greater consumer adoption of those smart

[42] At https://aemo.com.au/about/aemo-services/aemo-services-as-the-consumer-trustee.

[43] If distributed storage uptake is slower than assumed, more utility-scale shallow storage would be needed instead.

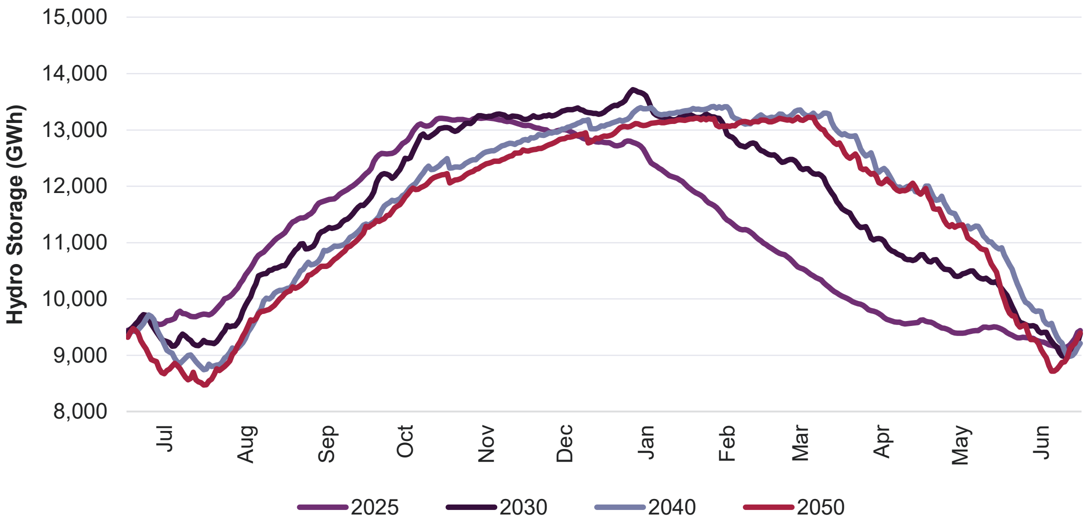
technologies, with support of retailers, networks and other market participants to overcome any adoption challenges: see Section 7.5.

Deep storage to manage seasonal variability

Deeper storage (and traditional hydro generation) is vital to manage seasonal and long duration variations in renewable resource availability. Figure 25 below shows two aspects of the seasonal cycle that will heavily influence NEM planning and operation:

- The vertical variation in the annual cycle shows how strong spring water inflows (from snow melt) builds up the potential renewable resource, enabling it to be discharged over the summer.
- The horizontal variations between the decades shows the impact of VRE on the annual cycle. As early as 2030, the additional VRE means that less discharge is required over summer[44], allowing the stored energy to be held over to autumn where solar generation is lower, and then into winter to meet heating needs as gas appliances are increasingly converted to electricity. This trend accelerates through to 2050. Snowy 2.0 provides much of the necessary additional storage depth to 2030 (see Figure 23 above), with additional storage needed in the 2030s and 2040s.

Figure 25 Daily energy stored in deeper storages and traditional hydro reservoirs over a year



The need for deep storage is inverse to the availability of coal-fired generation: the longer coal-fired generation is retained in the NEM, the less exposed it is to relying on weather-influenced generation. Therefore, it may be prudent for early investment in deep storage across the NEM, to enable improved resilience to earlier coal closures or project commissioning delays. (For similar reasons, earlier commencement of transmission projects is valued in selecting the ODP: see Section 6.)

For example, by 2030-31 Queensland is forecast to need approximately 2 GW of medium and deep storage to support renewable energy developments. However, when all Queensland coal capacity retires, the level of deeper storage increases to almost 6 GW, complementing over 10 GW of shallow storage at utility scale

[44] Although minimum releases for environmental or irrigation purposes are still anticipated.

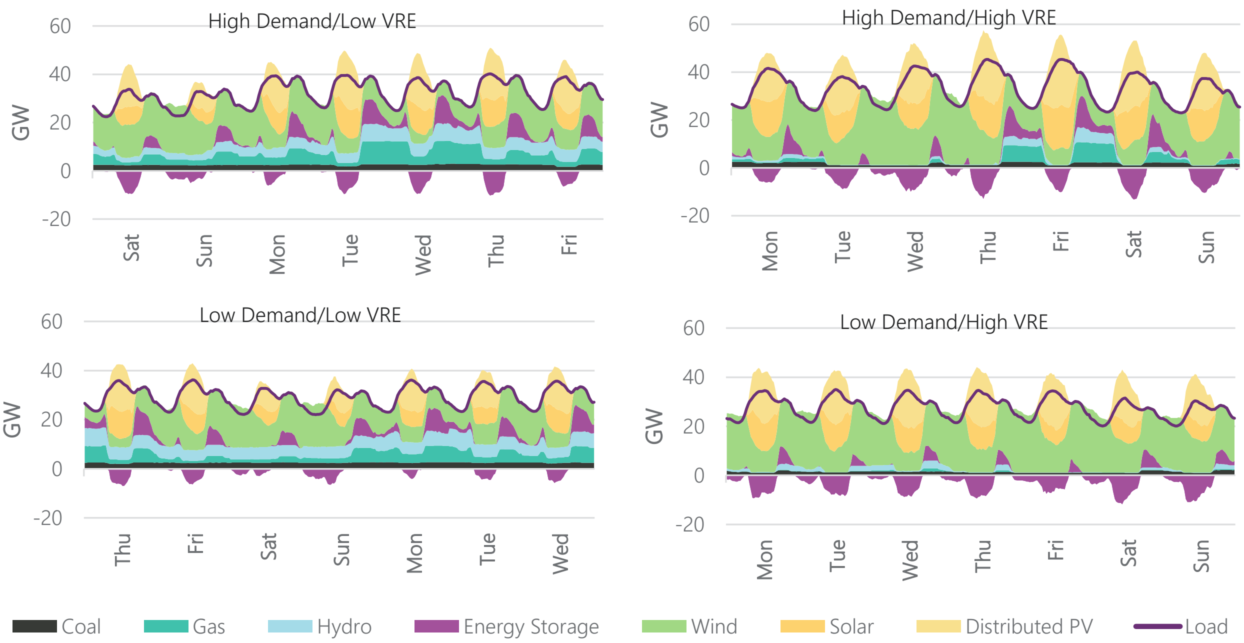
and/or within the distribution system. This total storage capacity is equivalent to 30 times the existing Wivenhoe Power Station, and over 20 times the scale of stored energy at Wivenhoe.

Peaking gas-fired generation needed to balance VRE variability

Peaking gas-fired generators will play a crucial role as significant coal-fired generation retires, as an on-demand fuel source during extended periods of low VRE output, and to provide power system services for grid security and stability: see Section 4.3. There would be limited opportunities for mid-merit gas as the cost of VRE declines relative to gas, unless VRE is limited by transmission access.

Peaking gas and storage would complement each other as firming technologies, particularly through weather conditions that do not favour VRE. Figure 26 shows weeks that are modelled with the four combinations of high and low demand, and high and low VRE generation.

Figure 26 Indicative generation mix in the NEM, *Step Change*, 2035



The figure demonstrates how the different mixes of generation and storage meet each week's challenges:

- **Low renewable output and high demand (top left)** – the system relies more on hydro, and gas, complemented in the evening peak by shallow storage (including VPP) charged from distributed PV and utility-scale solar during the day. Existing mid-merit gas-fired generators assist through the night, with peaking gas-fired generators needed in the evening and occasionally the morning peaks.
- **High renewable output and high demand (top right)** – gas is needed to meet the demand peaks just after sunset, and to keep going through the night to cover wind variability.
- **Low renewable output and low demand (bottom left)** – gas is needed through the night, particularly during winter, when solar output is lower.
- **High renewable output and low demand (bottom right)** – with VRE output well in excess of total demand, gas-fired generation is barely needed. Deeper storages fill their reservoirs from the excess energy.

Gas would retain its firming role even through periods of extremely high gas prices, such as those being experienced in mid-2022. The investment in VRE, DER, storage and peaking gas being proposed in this ISP will increasingly insulate consumers from the risk of rising international fuel prices, providing valuable energy independence. In the future power system, gas would be relied on for prolonged periods of low VRE, where equivalent investments in deep storage is prohibitively expensive, based on current assumptions. Future ISPs will continue to compare the relative merits of competing technologies, including emerging technologies such as hydrogen turbines, or potentially greater investment in long-duration storages, should costs of these come down more than currently anticipated.

4.3 Stronger services for power system requirements

Just as the NEM's generation and dispatchable resources are transforming, so too will the manner in which the power system services needed to keep the NEM secure and reliable are provided. For example, with fewer synchronous generating units, there are fewer sources of system strength, dynamic reactive support, inertia, primary frequency response and frequency control ancillary services that these units have traditionally provided. Likewise, there are fewer options for black restart services and sources.

There are several actions being taken to ensure these system services support the NEM as it decarbonises and decentralises as projected in this ISP.

- **AEMO's annual System Security Reports**[45] assess the current and five years' projected needs for system strength, inertia and network support and control ancillary services (NSCAS) in the NEM, and declares any shortfalls. The assessments are based on ISP modelling, and demonstrate the growing and accelerating need for system services as the system transforms.
- **AEMO's Engineering Framework**[46] enables industry participants to collaboratively define the operational, technical and engineering requirements for the NEM's future, and informs the market reforms being undertaken by the ESB. It describes the initial roadmap to inform preparation of the NEM for operation under six identified operational conditions[47], including contributing to 100% instantaneous renewable energy potential by 2025. Uplifts are needed in in real time monitoring, power system modelling, and control room technologies by AEMO and Network Service Providers, to ensure operational staff have the tools to maintain secure operation of the NEM power system as it transitions to significant penetrations of inverter-based resources including Distributed Energy Resources. AEMO has developed a strategic roadmap for this uplift[48].
- **Advanced inverters with grid-forming capabilities** and suitable design, placed at strategic sites in the NEM, have the potential to provide a range of future power system requirements. Advanced inverters are not yet demonstrated at the necessary scale to completely replace the services currently provided by synchronous generation in the NEM, and focused engineering is urgently needed to address the remaining issues and realise their promise. To this end, the Australian Renewable Energy Agency (ARENA) is currently exploring the viability of further funding to rapidly prove up the capability of advanced inverters at scale, and hosted a webinar on Monday, 8 November 2021 to gain insight on the

[45] At https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability.

[46] At https://aemo.com.au/initiatives/major-programs/engineering-framework.

[47] See https://aemo.com.au/newsroom/news-updates/engineering-framework-takes-shape.

[48] See https://aemo.com.au/initiatives/major-programs/operations-technology-roadmap.

ability to accelerate advanced inverter capabilities on battery projects and address the associated barriers.

These technical requirements are complemented by numerous regulatory and market reforms underway for essential system services, which are vital to enable participants to invest in and operate infrastructure that will provide system services in addition to energy. The market reforms already implemented or in advanced stages include:

- **Significant market reforms that have already been implemented.** On 1 October 2021, AEMO and its industry partners implemented Five Minute Settlement and Wholesale Demand Response in the NEM. These major reforms provide better price signals for fast response and flexible technologies, and enable businesses to provide peak shaving services in the spot energy market.
- **Further significant market reforms that are underway.** AEMO is working with the Energy Security Board (ESB) and its members, the Australian Energy Regulator (AER) and Australian Energy Market Commission (AEMC), progressing reform workstreams and associated initiatives, including:
  - **Resource Adequacy Mechanism,** including a **Capacity mechanism**, to create a clear, long-term signal for investment, in both existing and new dispatchable capacity. Enhancements to Medium Term Projected Assessment of System Adequacy (MT PASA) are also in train to improve transparency of capacity which is available to the market.
  - **Essential System Services**, to progress and deliver a number of initiatives to maintain the system's secure operation and unlock value for consumers, including system strength, frequency, operating reserve and inertia.
  - **DER Integration** to ensure these resources are coordinated, including through some active management for efficient operation and export.
  - **Transmission reform** and **congestion management** mechanism, to consider the case for a congestion management mechanism to improve market signals for generator connections.

    The AEMC's Transmission Planning and Investment Review (TPIR) aims to ensure that future transmission infrastructure can be delivered in a timely and efficient manner to meet decarbonisation objectives, by proposing amendments to the existing regulatory framework to better facilitate key enablers such as social licence, an appropriate economic assessment framework including cost estimation accuracy, financeability and cost recovery. Incremental reforms will be proposed towards the end of 2022, while longer-term reforms will be proposed in 2023.

Part C
The Optimal Development Path

Part B presented a re-imagined future power system that will require community support for large amounts of renewable resource and dispatchable generation to achieve the decarbonisation goals for the NEM.

AEMO has now conducted a rigorous analysis of the network investments needed to serve that power system, and the optimal path for their development.

This Part C presents:

- **Section 5: The ODP and its network investments.** The ODP defines the project and timing of 22 network investments, together with the ISP development opportunities set out in Part B. If these network investments are completed, they would deliver over $28 billion in net market benefits to consumers, while fulfilling public policy needs, security, reliability and sustainability expectations, and managing risk through a complex transformation, and
- **Section 6: The rationale that supports the ODP**, in particular, the timing and early works of the actionable projects, following the steps set out in the *ISP Methodology.*

AEMO stresses that the ODP integrates both network projects and ISP development opportunities. The network projects are key to enabling the development of the VRE, storage and gas-fired generation discussed. Changing one set is likely to render both the other set, and the whole, sub-optimal.

5 The optimal development path

The ODP identified in this 2022 ISP is based on information published in the 2021 IASR[49], with minor updates to information published in the Updated Inputs and Assumptions workbook[50]. The ODP comprises both the ISP development opportunities described in Part B, and the network investments described in this Section 5. This section lays out:

- an overview of the committed, anticipated, actionable and future ISP projects that are included in the ODP,
- an overview of the $28 billion in net market benefits that these network investments deliver for the NEM's consumers, and
- key information for actionable projects, including their identified need, estimated cost, and net market benefits.

The detailed analysis leading to the selection and timing of these network investments is set out in Section 6.

The ODP identified in this 2022 ISP is based on information published in the 2021 IASR, with minor updates to information published in the Updated Inputs and Assumptions workbook.

5.1 Network investments in the ODP

The following network investments are identified as part of the ODP in Figure 27 and described through Sections 5.3 to 5.5. Further details on each project are set out in Appendix 5.

- **Committed and anticipated projects** – Eyre Peninsula Link, Queensland – New South Wales Interconnector (QNI) Minor, Victoria – New South Wales Interconnector (VNI) Minor, Central West Orana REZ Transmission Link, Northern QREZ Stage 1, Project EnergyConnect (PEC), and Western Renewables Link.
- **Actionable projects**:
  - ISP Framework: HumeLink, Marinus Link (cable 1 and 2) and VNI West (via Kerang).
  - NSW Framework[51]: Sydney Ring and New England REZ Transmission Link.
- **Future ISP projects** – QNI Connect, Central to Southern Queensland, Gladstone Grid Reinforcement, New England REZ Extension, Darling Downs REZ Expansion, Far North Queensland REZ Expansion, Facilitating Power to Central Queensland, South East South Australia REZ Expansions, Mid North South Australia REZ Expansion, and South West Victoria REZ Expansion.

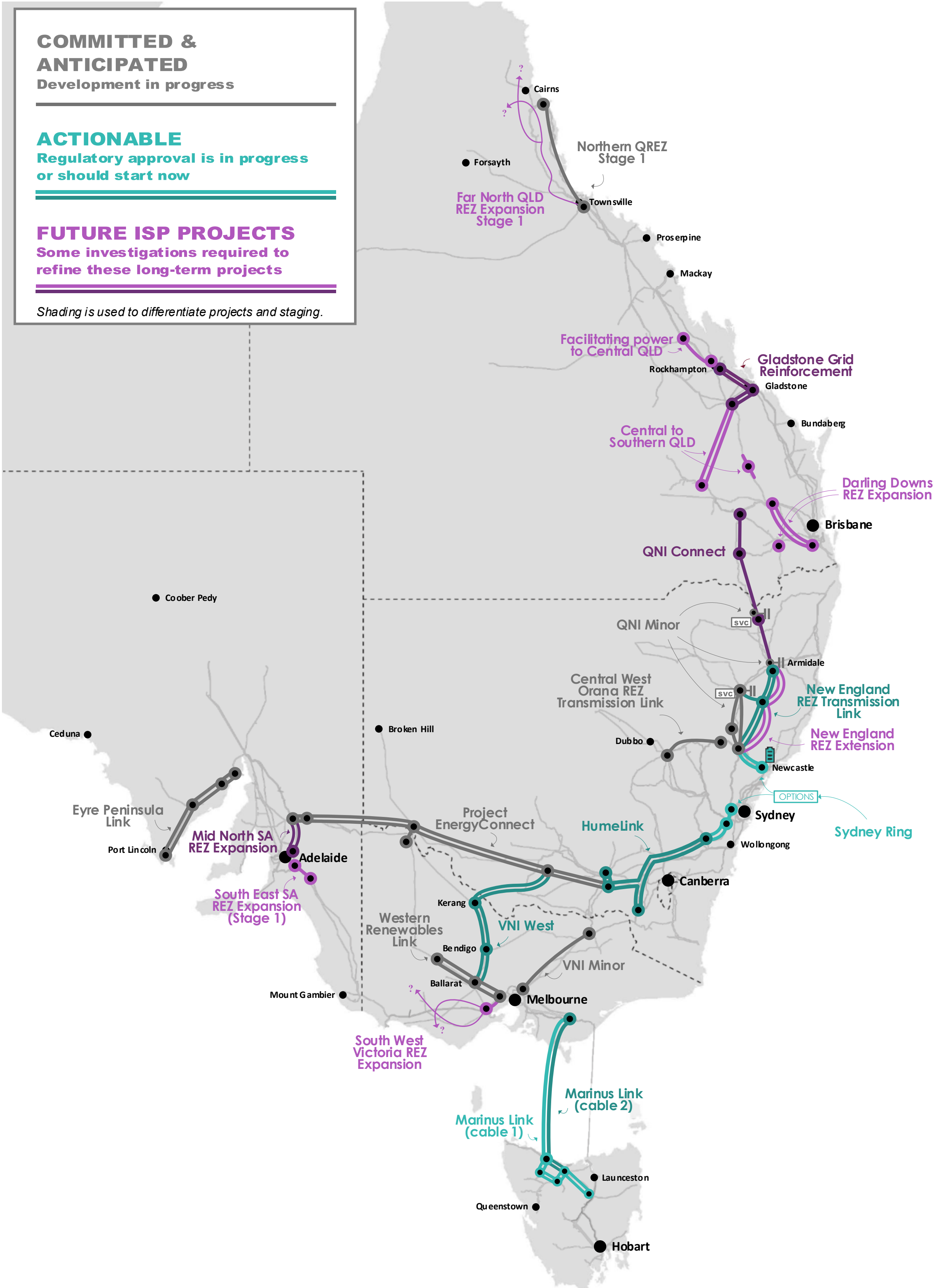
Together, these projects comprise approximately 10,000 km of new network investment for the efficient connection and operation of the resources that comprise the ODP.

[49] Minor updates to inputs and assumptions are outlined in the 2021 Inputs and Assumptions workbook, available at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

[50] Inputs and assumptions have been updated to accommodate stakeholder feedback on the Draft ISP and the latest market information. These changes are outlined in the *2022 ISP Consultation Summary Report*.

[51] Actionable NSW projects will progress under the *Electricity Infrastructure Investment Act 2020* (NSW) rather than the ISP framework. The northern part of the Sydney Ring project has been named the Hunter Transmission Project and may include the Waratah Super Battery and related upgrades.

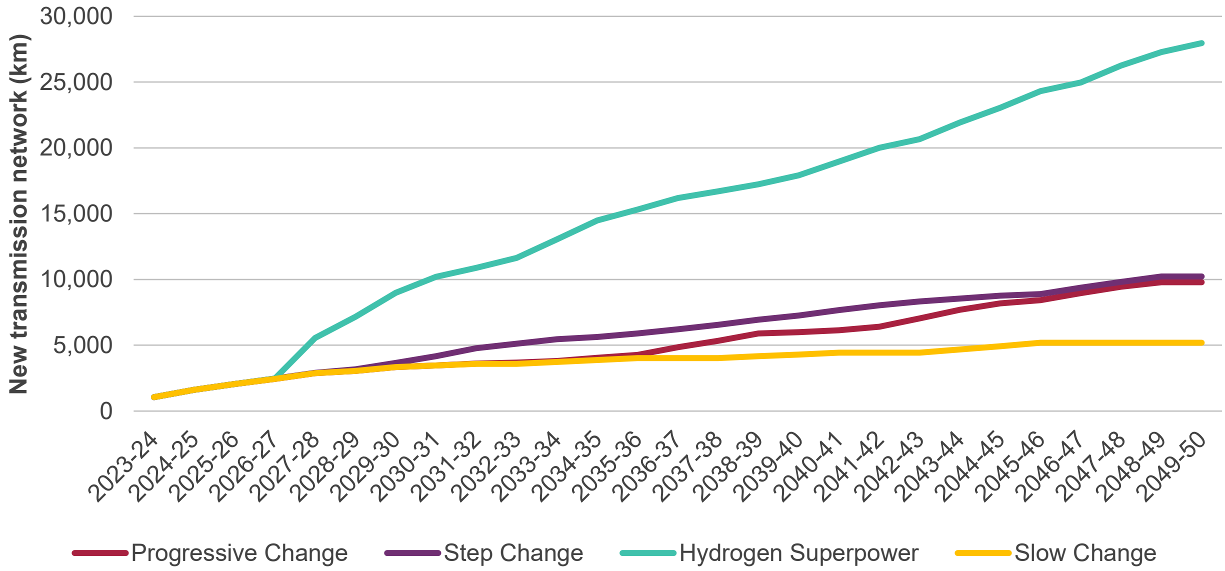
Figure 27 Map of the network investments in the optimal development path



† Additional projects to expand REZs and upgrade flow paths after 2040 are highly uncertain, vary significantly between scenarios, and are not shown on this map. See Appendix 5 for more information.

The scale and timing of optimal network investment depends on the scenario: see Figure 28. The more likely *Step Change* and *Progressive Change* scenarios both foresee approximately 10,000 km of new transmission by 2050. Their development path is relatively linear, indicating a steady roll out of transmission at a rapid yet sustainable pace, both to meet the needs of the NEM and to sequence demand for skills, labour, plant and materials: see Section 7.4. While this scale of infrastructure is needed to support Australia's transition to a net zero future, it will need to secure social licence in the lands through which it passes: see Section 7.3.

Figure 28 New transmission network required in the ODP



5.2 The ODP and its benefits

The primary benefits of the ODP are that it would:

- provide a reliable and secure power supply,
- deliver $28 billion in net market benefits[52] by saving costs elsewhere,
- retain flexibility to decarbonise the NEM at least as fast as current government, corporate and societal ambitions, and
- be resilient to events that can adversely impact future costs to consumers, and relatively insensitive to changes in input assumptions.

Net market benefits of the network investments

The ODP is calculated using the *ISP Methodology* to offer $28 billion in net market benefits for consumers. This is the net present value (NPV) of the annual benefits offered through to 2050-51, probability-weighted across the four modelled scenarios.

[52] Net present value (NPV) of annual net market benefits from 2021-22 to 2050-51, weighted across the scenarios by their relative likelihood: see Section 2.3 for scenario weightings.

The benefits of the new network infrastructure increase with the pace of reducing the NEM's emissions: the benefits are higher benefits in scenarios with faster reductions in emission intensity. The investments deliver up to $3.5 billion in net market benefits in the *Slow Change* scenario, $15.1 billion in *Progressive Change*, $24.5 billion in *Step Change,* and $64.6 billion in *Hydrogen Superpower:* see Table 4 below.

These benefits highlight the value of the transmission network in an efficient power system transformation. The network would allow NEM consumers to secure the full benefit of zero-emission VRE generation, which will become even more cost-efficient over the ISP time horizon. Without that transmission, the NEM would require more expensive generation capacity nearer to load centres – either offshore wind, or gas-fired generation with carbon capture and storage (CCS) to manage its cumulative emissions. These technologies have higher capital costs than land-based VRE[53] with, in the case of gas, higher fuel costs.

Table 4 Market benefits of the ODP ($M, NPV)

Class of market benefit	*Slow Change*	*Progressive Change*	*Step Change*	*Hydrogen Superpower*	Scenario weighted
Scenario weighting	**4%**	**29%**	**50%**	**17%**	
Generator and storage capital deferral	6,058	8,825	17,740	55,381	21,087
FOM cost savings	926	662	2,455	15,081	4,020
Fuel cost savings	3,673	13,710	14,979	7,481	12,884
VOM cost savings	-13	283	334	22	252
USE+DSP reductions	8	7	-385	3,862	467
Gross market benefits	10,651	23,488	35,122	81,827	38,709
Network projects (Flow paths[54])	-7,067	-7,127	-8,540	-10,503	-8,405
Network projects (REZ expansion)	-55	-1,263	-2,105	-17,095	-4,327
Total network cost[55]	-7,122	-8,390	-10,644	-27,599	-12,732
Network cost (counterfactual)	-	-	-	10,357[56]	1,761
Additional network cost (relative to counterfactual)	-7,122	-8,390	-10,644	-17,242	-10,971
Total net market benefits	3,529	15,097	24,478	64,586	27,738
Return on investment (ratio):					
• **all network investments**	0.5	1.8	2.3	2.3	2.2
• ***additional to counterfactual***	*0.5*	*1.8*	*2.3*	*3.7*	*2.5*

FOM: fixed operating and maintenance. VOM: variable operating and maintenance.

Imagining the NEM without transmission investment

It may be helpful to illustrate the net market benefits of the actionable projects by considering the NEM without that transmission investment. Figure 29 below sets out the generation capacity that would be needed in the *Step Change* scenario, with and without these network investments. Without them, the NEM can continue to

[53] CSIRO. *GenCost 2020-21*, at https://www.csiro.au/-/media/EF/Files/GenCost2020-21_FinalReport.pdf.

[54] Flow paths are the portion of the transmission network used to transport significant amounts of electricity across the backbone of the interconnected network to load centres.

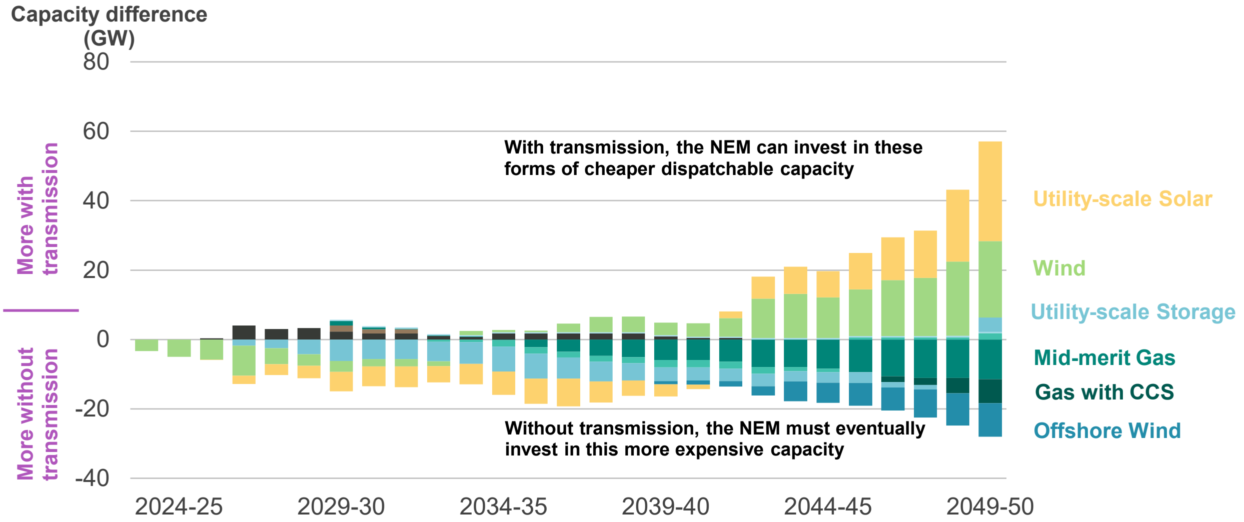
[55] This does not reflect the full capital investment in network in today's dollars, but rather the NPV of the equivalent annuity calculated from time of commissioning to 2050-51.

[56] Some network investment is required in the *Hydrogen Superpower* counterfactual to enable energy to operate hydrogen export facilities, as explained in Appendix 2, Section A2.3.3.

invest in solar, wind and storage for about 15 years or so, utilising spare shared-network capacity until it gets saturated. From that point, without additional transmission, the NEM has no choice but to turn to more expensive gas-fired generation and offshore wind.

The additional gas-fired generation would also add to the NEM's carbon emissions in later years. Keeping the NEM within its assumed carbon budget would incur additional costs. Initially, coal would need to reduce operation and withdraw earlier to leave more of the carbon budget for later in the ISP horizon. Later, some combination of technologies would be needed to manage emissions from gas-fired generation: for example, CCS where available, or additional land use sequestration, or the use of hydrogen or biomethane instead of natural gas.

Figure 29 Differences in capacity needed in *Step Change*, with and without new network



Through network investment, cost savings can therefore be delivered for consumers:

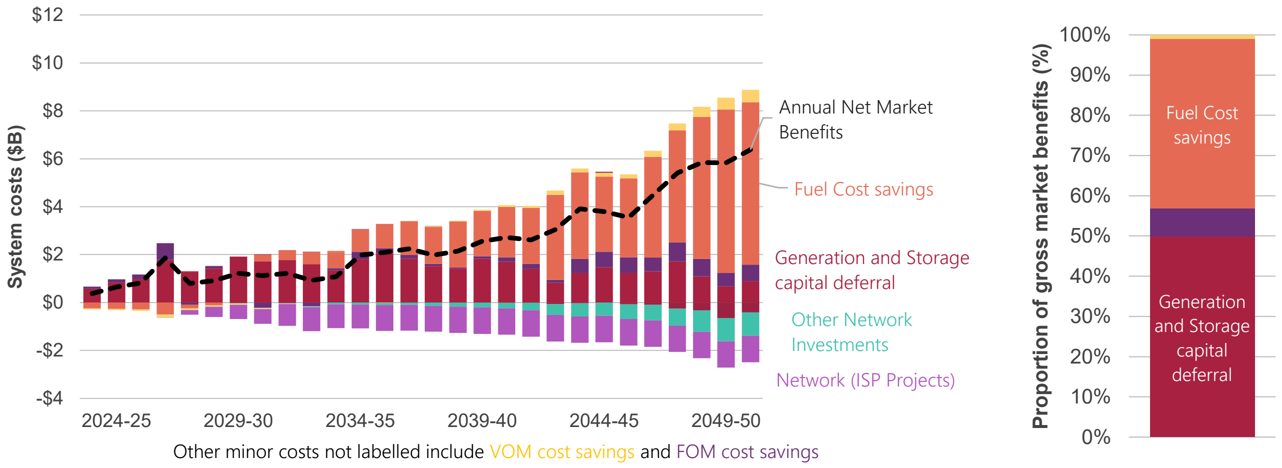
- **in the next 15 years**, by balancing use of existing generation against even-more-rapid development of VRE and storage to achieve the decarbonisation outcomes over the ISP horizon.
- **in the longer term**, by avoiding the need to rely on greater volumes of gas-fired generation and generation technologies that are currently more costly such as off-shore wind (and associated fixed operating and maintenance [FOM] costs). This benefit is forecast to increase over time and will continue to be realised beyond the ISP's 2050 planning horizon.

Capital and operating cost benefits

Of the total benefits, 50% are from deferring or avoiding the capital cost of generation and storage projects, and 40% from fuel cost savings (see Figure 30).

Fuel cost savings become a larger part of the annual savings from 2041 onwards. However, the earlier savings in capital costs contribute most overall due to the time value of money. (For this reason, the ODP is tested against material changes to discount rates and gas prices: see Appendix 6).

Figure 30 Net market benefits by benefit category, *Step Change* least-cost development path



5.3 Committed and anticipated network projects

The earliest projects in the ODP already have regulatory approval and are highly likely to proceed. They are therefore included in the modelling for all development paths, scenarios and sensitivities. Table 5 below gives an overview of:

- **committed network projects**, which meet all five commitment criteria in the *ISP Methodology*[57] (relating to site acquisition, components ordered, planning approvals, finance completion and set construction timing), and
- **anticipated network projects**, which are in the process of meeting at least three out of the five criteria, and have been consulted on through the 2021 IASR.

Table 5 Committed and anticipated network investments in the optimal development path

Project	Advised delivery date†	Description	Regulatory status
VNI Minor	Nov 2022	An incremental upgrade to the transfer capacity of the existing VNI.	Committed
Eyre Peninsula Link	Early-2023	A network upgrade that will improve reliability and network capacity on the Eyre Peninsula in South Australia.	Committed
QNI Minor	Mid-2023[58]	An incremental upgrade to the transfer capacity of the existing QNI.	Committed
Northern QREZ Stage 1	Sept 2023	A network upgrade to provide additional capacity to the Far North Queensland REZ.	Anticipated
Central West Orana REZ Transmission Link	Mid-2025	A network upgrade to provide additional capacity to the Central West Orana REZ.	Anticipated
Project EnergyConnect	July 2026‡	A new 330 kilovolt (kV) double-circuit interconnector between South Australia and New South Wales.	Anticipated
Western Renewables Link	July 2026	A network upgrade to provide additional capacity to the Western Victoria REZ. This project was previously named "Western Victoria Transmission Network Project".	Anticipated

† Reflects the latest project timing for the full release of capacity as advised by the relevant TNSP.
‡ This delivery date for PEC refers to full capacity available following completion of inter-regional testing, and timing is updated according to the latest advice provided by the relevant TNSPs. The ISP modelling, using information available at the time, modelled the service date as July 2025.

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

[58] This timing is when full capacity is expected to be available following commissioning and interconnector testing. The timing is as per the QNI Upgrade Project Test Program for Inter-Network Test available at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/qld-to-nsw-interconnector-qni-upgrade/final-inter-network-test-program-document.pdf?la=en.

5.4 Actionable projects

Actionable projects optimise benefits for consumers if progressed before the next ISP. They are identified in Table 6 below, with further information on each project below the table, and their complete and detailed technical information in Appendix 5.

All actionable projects should progress as urgently as possible. The delivery dates for actionable projects are largely dictated by their earliest practical delivery time as advised by the project proponents. In some cases, the optimal timing would be earlier than what is achievable; in others any earlier delivery provides valuable insurance against faster-than-expected coal closures or slower-than-expected VRE and storage development. As suggested below, supporting policies and mechanisms from the Commonwealth and jurisdictional government may be able to assist in earlier delivery.

For actionable ISP projects identified in this 2022 ISP, the relevant TNSP must assess the project under the RIT-T, using the identified need and investment identified in this section as one of the RIT-T credible options.

In addition to actionable ISP projects, AEMO also notes actionable New South Wales projects, where augmentations will be assessed under the *Electricity Infrastructure Investment Act 2020* (NSW) rather than through the RIT-T.

Table 6 Actionable network investments in the optimal development path

Project	Actionable ISP delivery date – to be progressed urgently[Ω]	Description	Actionable framework
HumeLink	July 2026	A 500 kV transmission upgrade connecting Project EnergyConnect and the Snowy Mountains Hydroelectric Scheme to Bannaby. Cost estimates of $330 million (stage 1) and $2,985 million (stage 2).	ISP (RIT-T is complete)
Sydney Ring [¥]	July 2027	High capacity 500 kV transmission network to reinforce supply to Sydney, Newcastle and Wollongong load centres. Cost estimates of $0.9 billion ±50% for northern option, and $2.25 billion ±50% for southern alternative option.	NSW [†]
New England REZ Transmission Link	July 2027	Transmission network augmentations as defined in the New South Wales Electricity Strategy, costing $1.9 billion ±50%.	NSW [†]
Marinus Link	Cable 1: July 2029 Cable 2: July 2031	Two new HVDC cables connecting Victoria and Tasmania, each with 750 MW of transfer capacity and associated alternating current (AC) transmission, costing $2.38 billion ±30% (cable 1) and $1.40 billion ±30% (cable 2). [‡]	ISP (RIT-T is complete)
VNI West	July 2031	A new high capacity 500 kV double-circuit transmission line to connect Western Renewables Link (north of Ballarat) with Project EnergyConnect (at Dinawan) via Kerang, costing $491 million (stage 1) and $2.5 billion* (stage 2).	ISP (RIT-T is in progress)

Ω This actionable ISP delivery date is the optimal ISP timing, and aligns with advice from project proponents as to the earliest practical delivery time under current arrangements. Work needs to commence urgently to manage potential risks to delivery. Earlier delivery could provide additional resilience benefits, and would require additional supporting arrangements to accelerate the timeline
† The New England REZ Transmission Link[59] and Sydney Ring project are actionable NSW projects rather than actionable ISP projects. They will progress under the *Electricity Infrastructure Investment Act 2020* (NSW) rather than the ISP framework.
¥ The northern part of this project is named the *Hunter Transmission Project* and may include the *Waratah Super Battery* and related upgrades.
‡ On 20 June 2022, Marinus Link announced that the cost of the project increased by approximately 8%. The latest costs are shown in this table. AEMO has assessed that this change does not impact on the optimal timing of Marinus Link – see Appendix 6 for more information. The Marinus Link announcement is available at https://www.marinuslink.com.au/2022/06/marinus-link-project-update/.
* Estimates for costs for the New South Wales works on VNI West include estimates provided by Transgrid. As the information provided did not allow AEMO to transparently confirm these classifications, the accuracy and class of the estimates are stated as 'unknown' in this report.

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[59] NSW Government. *New England Renewable Energy Zone declaration*, at https://www.energy.nsw.gov.au/renewables/renewable-energy-zones/new-england-renewable-energy-zone-declaration.

HumeLink

HumeLink is a proposed 500 kilovolts (kV) transmission project that links the Greater Sydney load centre with the Snowy Mountains Hydroelectric Scheme and Project EnergyConnect in South West NSW.

HumeLink is a staged actionable ISP project without decision rules, having had decision rules in the Draft 2022 ISP: see 'Decision rules no longer apply' below. **Stage 1** is to complete the early works by approximately 2024, and **Stage 2** is to complete implementation by July 2026. Making the project actionable with this delivery date protects consumers against schedule slippage or further coal closures, while staging the project retains the option to pause the project if circumstances change.

Optimal benefits and timing

The rationale for HumeLink being included as part of the ODP is set out extensively step-by-step in Section 6 below, and in Appendix 6, and is summarised here.

HumeLink would contribute roughly $1.3 billion of the $24.5 billion in net market benefits delivered by the ODP in the most likely *Step Change* scenario. It delivers value in all scenarios, although the optimal timing differs.

In AEMO's view, the project would *optimise* benefits to consumers if delivery is targeted for 2026-27. The ISP modelling does suggest that net market benefits would be $3 million more if HumeLink were scheduled to be delivered in 2028-29 in *Step Change* and 2033-34 in *Progressive Change*: see Section 6[60]. However, the later schedules would provide less valuable protection against the risks of project slippage or early coal closures.

The value of the project is in mitigating the risk that not enough dispatchable capacity is available if there are early coal closures in the period 2026 to 2028. That risk may be realised if a third New South Wales coal-fired power station (including Liddell) retires, and two of those four closures have already been announced as likely to occur by 2025.

HumeLink is the only actionable ISP project that could be delivered in the critical period that directly addresses this risk. If HumeLink is not delivered on time, more long-duration storage than is anticipated under the NSW Electricity Infrastructure Roadmap and/or additional gas-fired generation would be needed to maintain power system reliability in New South Wales.

The insurance cost (in reduced net market benefits) of securing this benefit is just $3 million (or 0.01% of overall net market benefits). There would only need to be a 4% possibility of a two-year project delay or a 1% chance of further coal closure by 2026-27 for that insurance to be worth taking. AEMO's engagement with consumer advocates indicates that a staged approach to deliver HumeLink by 2026-27, along with the protections of the ISP Feedback Loop, broadly aligns with consumer risk preferences: see Appendix 1.

A staged delivery provides protection against rising project costs. A material increase in project costs will test the timing of the project and the rationale of the ODP. Further work to drive down costs should be undertaken urgently and, if necessary, a government co-contribution could be considered in recognition of the broader economic and societal value this project delivers. Transgrid's staged approach to HumeLink will help reduce cost uncertainties, and so build greater consumer confidence that they will not be over- or under-investing.

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[60] The delayed timing when compared with the 2020 ISP is a result of significant project cost increases, additional investments in dispatchable capacity in New South Wales, and the need to complete Sydney Ring to realise the full benefits of HumeLink.

Identified need

The identified need for this HumeLink project has not changed since the 2020 ISP or the Draft 2022 ISP:

To deliver a net market benefit by:

- *increasing the transfer capacity and stability limits between the Snowy Mountains and major load centres of Sydney, Newcastle and Wollongong*
- *enabling greater access to lower cost generation to meet demand in these major load centres; and*
- *facilitating the development of renewable generation in high quality renewable resource areas in southern New South Wales, which will further lower the overall investment and dispatch costs in meeting New South Wales demand while also ensuring emissions targets are met at the lowest overall cost to consumers.*

Next steps

The regulatory approval process for the project's Stage 1 early works (listed below) is progressing. Transgrid completed the HumeLink RIT-T[61] in December 2021. AEMO completed the ISP feedback loop[62] on the first stage in January 2022, confirming that the early works aligned with the ISP.

- **Next steps for regulatory approval.** Transgrid's recent funding request to the AER for early works[63] effectively delivers the staging that the ISP identifies as in consumers interest. The next milestone for the project is the AER's assessment of the prudent and efficient cost of early works – which is expected in the second half of 2022. AEMO will then need to evaluate the project's Stage 2 implementation through another feedback loop assessment of the entire project.
- **Decision rules no longer apply:** The decision rules that were outlined in the Draft 2022 ISP have been removed for the HumeLink project. After considering stakeholder feedback, AEMO now considers that decision rules should only apply when they can be very clearly defined (for example, a known policy being legislated or a specific power station announcing its closure). Project implementation (Stage 2) remains subject to the ISP feedback loop, which will assess whether the project remains aligned with the latest ISP prior to final investment decision.
  - Importantly, removal of the decision rules defined in the Draft 2022 ISP that would trigger the progression of Stage 2 do not reduce consumer protections against over-investment. The satisfaction of HumeLink's Draft 2022 ISP decision rules would simply have allowed a feedback loop for Stage 2 to be requested. The feedback loop assessment itself comprehensively tests alignment with the ODP, including by re-running the ISP modelling if necessary, by considering multiple complex interactions that are unable to be captured within decision rules.
- **Early works** for HumeLink includes[64]:

[61] Transgrid. *HumeLink RIT-T*, at https://www.transgrid.com.au/projects-innovation/humelink.

[62] AEMO. Feedback Loop Notices, at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/integrated-system-plan-feedback-loop-notices.

[63] AER. *Transgrid - Humelink contingent project*, at https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/contingent-projects/transgrid-humelink-contingent-project/initiation.

[64] Transgrid. *HumeLink – Stage 1 (Early Works) Contingent Project Application*, at https://www.aer.gov.au/system/files/A1%20HumeLink%20Stage%20%28Early%20Works%29%20CPA%20Principal%20Application%20-%205%20April%202022.pdf.

- **Community engagement** – implementing stakeholder and community programs, including community support, social legacy, design and communication and community improvement.
- **Land planning** – land and environmental planning studies and approval activities.
- **Land acquisition** – acquiring land for a new substation and binding land options for transmission line easements.
- **Procurement activities** – the design and delivery of nine standard steel transmission towers, procurement of equipment with long lead times, and pre-construction development of substations and transmission lines.
- **Labour** – project management and labour to support environmental activities and land acquisition.
- **Project development** – engineering, legal and economic support.
- **Regulatory approvals** – completion of the HumeLink RIT-T and subsequent contingent project applications.

Sydney Ring (Reinforcing Sydney, Newcastle and Wollongong Supply)

The Sydney Ring project increases transfer capacity into the Sydney, Newcastle and Wollongong area by approximately 5,000 MW. It should commence immediately, to support REZ development in the New South Wales Government's Electricity Infrastructure Roadmap and maintain reliability of supply for New South Wales consumers.

Sydney Ring is an actionable New South Wales project for delivery in 2027-28, having been a future ISP Project in the 2020 ISP and an actionable ISP project in the Draft 2022 ISP. The northern part of this project is named the *Hunter Transmission Project* and may include the *Waratah Super Battery* and related upgrades. As an actionable New South Wales project, this project will progress under the *Electricity Infrastructure Investment Act 2020* (NSW) rather than the ISP framework. It is also identified as a REZ-critical project in the 2021 Infrastructure Investment Objectives (IIO) report[65] published by AEMO Services' (as the New South Wales' Consumer Trustee).

Optimal benefits and timing

The rationale for Sydney Ring being included as part of the ODP is set out step-by-step in Section 6 below, and more extensively in Appendix 6. This is a short summary.

Sydney Ring contributes roughly $3.4 billion of the $24.5 billion in net market benefits delivered by the ODP in the most likely *Step Change* scenario, and is also part of all other high-ranking CDPs. The project will assist in maintaining reliability of supply for New South Wales consumers following the closure of coal in the Newcastle area. Alternative solutions may be available, but would come at a much higher cost for consumers. The alternatives include peaking support and annual energy production in close proximity to Sydney's major loads, nearby deeper storages to support energy transfers into the Sydney Ring at other times, offshore wind projects that connect to existing transmission corridors, and greater voluntary load reductions (to be compensated appropriately).

[65] At https://aemo.com.au/about/aemo-services/aemo-services-as-the-consumer-trustee.

The optimal timing in all scenarios other than the unlikely *Slow Change* is as soon as possible (assumed to be by 2027–28). Postponing actionability until the 2024 ISP would reduce scenario-weighted net market benefits by $140 million, and increase scenario-weighted worst regret costs by approximately $40 million (or up to $200 million in *Hydrogen Superpower*).

Depending on route, the project is estimated to cost between $0.9 billion (northern option) and $2.25 billion (southern option) ±50%. The project is optimally timed for delivery in 2027-28 if costs are within the higher end of the northern options' cost range, or the middle of the range for the southern option: see the next step assessments below.

Identified need

The identified need for the Sydney Ring project is:

> *Deliver net market benefits for consumers by increasing the power system's capability to supply the Sydney, Newcastle and Wollongong load centres, replacing supply capacity that will be removed on the closure of coal-fired power stations in the Newcastle area.*

Next steps

As an actionable New South Wales project, this project will progress under the *Electricity Infrastructure Investment Act 2020* (NSW) rather than the ISP framework. To inform the design process[66], AEMO recommends that combinations of the following options be considered for the Sydney Ring project:

- A **northern network option** – 500 kV link between the Eraring and Bayswater substations, also known as the Hunter Transmission Project.
- A **southern network option** – 500 kV link between Bannaby and a new substation in the locality of South Creek[67].
- **Virtual transmission** – a System Integrity Protection Scheme (SIPS) as part of a staged delivery (for example, the Waratah Super Battery[68]).
- **Other minor network upgrades** – including, but not limited to, the uprating of relevant existing 330 kV lines (such as Bannaby – Sydney West 330 kV line).

New England REZ Transmission Link

The New England REZ Transmission Link is a transmission network augmentation as defined in the New South Wales Electricity Strategy, to support the New England REZ.

The project is an actionable New South Wales project for delivery in 2027-28, having been a future ISP project in the 2020 ISP and an actionable ISP project in the Draft 2022 ISP. As an actionable New South Wales project, this project will progress under the *Electricity Infrastructure Investment Act 2020* (NSW) rather than the ISP framework. It is also identified as a REZ-critical project in the 2021 IIO report published by AEMO Services (as the New South Wales' Consumer Trustee).

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[66] The Sydney Ring project will be progressed under the *Electricity Infrastructure Investment Act 2020* (NSW). For more information, refer to the letter from the New South Wales Minister for Energy at https://aemo.com.au/consultations/current-and-closed-consultations/2022-draft-isp-consultation.

[67] The southern Sydney Ring network option may subsequently proceed through the New South Wales, ISP or RIT-T framework.

[68] NSW Government. *Waratah Super Battery*, available at https://www.energy.nsw.gov.au/waratah-super-battery.

Optimal benefits and timing

The rationale for the New England REZ Transmission Link being included as part of the ODP is set out step-by-step in Section 6 below, and more extensively in Appendix 6. This is a short summary.

New England REZ Transmission Link contributes roughly $5.5 billion of the ODP's $24.5 billion in net market benefits in the most likely *Step Change* scenario, and is also part of all other high-ranking CDPs. It will unlock approximately 6,000 MW of VRE and storage capacity in the New England REZ, helping meet the objectives of the New South Wales Electricity Infrastructure Roadmap. ISP modelling suggests that New England has the potential to become one of the largest REZs in the NEM: see Figure 15. Without this project, investment in more expensive, larger-scale and/or poorer quality alternative generation and transmission resources would be needed.

The optimal delivery time is 2027-28 for all scenarios. A delay of two years would reduce scenario-weighted net market benefits by $110 million, and increase the scenario-weighted regret costs of under-investment by approximately $80 million (or $500 million in *Hydrogen Superpower*).

The project is estimated to cost $1.9 billion ±50%. At the higher end of this cost range, the project is still optimally timed for delivery in 2027-28, but only just. Its status as an actionable project is not affected by materially higher discount rates, materially lower gas prices, or any other variations in inputs tested through sensitivity analysis: see Section 6.4.

Identified need

The identified need for this project is:

> *To increase the capability of the transmission network to enable the connection of expected generation in the New England REZ:*
>
> – *increasing the transfer capacity between expected generation in the New England REZ and the existing transmission network in the Hunter region, and*
>
> – *ensuring sufficient resilience to avoid material reductions in transfer capacity during an outage of a transmission element*
>
> *or as otherwise consistent with the New South Wales Government's Electricity Infrastructure Roadmap.*

Next steps

On 17 December 2021, the New England REZ was formally declared to progress under the NSW Electricity Infrastructure Roadmap rather than the ISP framework. This declaration notes that EnergyCo NSW will be the infrastructure planner responsible for coordinating the development of the REZ. More information about the delivery of the New England REZ is available on the New South Wales Government website[69].

Marinus Link

Marinus Link will deliver two new high voltage direct current (HVDC) cables connecting Victoria and Tasmania, each with 750 MW of transfer capacity and associated alternating current (AC) transmission.

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[69] NSW Government. *New England Renewable Energy Zone declaration*, at https://www.energy.nsw.gov.au/renewables/renewable-energy-zones/new-england-renewable-energy-zone-declaration.

Marinus Link is a single actionable ISP project without decision rules, as it was in the Draft 2022 ISP, having been a staged actionable ISP project with decision rules in the 2020 ISP. As outlined in the Draft 2022 ISP, decision rules in the 2020 ISP relating to the Tasmanian Renewable Energy Target (TRET) and cost allocation are no longer required because TRET was legislated in November 2020 and cost allocation risks are instead recognised as a key project risk (see Section 7.2).

Optimal benefits and timing

The rationale for Marinus Link being included as part of the ODP is set out step-by-step in Section 6 below, and more extensively in Appendix 6. This is a short summary.

Marinus Link delivers positive net market benefits on a scenario-weighted basis, including $4.5 billion[70] of the ODP's $24.5 billion in the most likely *Step Change* scenario, and is also part of all other high-ranking CDPs. It provides improved access to Tasmania's dispatchable capacity (including deep storages) and high quality VRE opportunities, helping reduce the scale of investment needed on the mainland.

Wind farms located in Tasmania (particularly Tasmania's Central Highlands and North-West REZs) produce more energy than almost all REZs on the mainland, and also provide greater resource diversity to mainland wind farms. Without improved access to these resources, more mainland capacity would be required for the equivalent volume of energy, which would increase system costs all else being equal.

Marinus Link is a single actionable ISP project, without staging between the first and second cables. The optimal delivery in *Step Change* is 2029-30 for cable 1, and 2031-32 for cable 2. Any delay reduces net market benefits in all scenarios but the unlikely *Slow Change*.

The project's two cables are estimated to cost $2.38 billion ±30% (cable 1) and $1.40 billion ±30% (cable 2). At the higher end of this cost range, the project may no longer be optimally timed for delivery as soon as possible, but the regret of having invested too early is small. Its status as an actionable ISP project is not affected by materially higher discount rates, materially lower gas prices, or any other variations in inputs tested through sensitivity analysis (see Section 6.4).

Identified need

The identified need for the Marinus Link project has not changed since the 2020 ISP or the Draft 2022 ISP:

> *The characteristics of customer demand, generation and storage resources vary significantly between Tasmania and the rest of the NEM. Increased interconnection capacity between Tasmania the other NEM regions has the potential to realise a net economic benefit by capitalising on this diversity.*

Next steps

TasNetworks has completed a RIT-T to determine the preferred option for Marinus Link. The next step in the regulatory approval process for this project is the feedback loop.

[70] On 20 June 2022, Marinus Link announced that the cost of this project had increased by approximately 8%. The impact of this revision has not been included in these numbers but does not impact on the optimal timing of Marinus Link – see Appendix 6 for more information.

VNI West

VNI West (via Kerang) is a proposed 500 kV interconnector from a substation near Ballarat in Victoria to a new substation named Dinawan in southwest New South Wales.

The project is an actionable ISP project without decision rules, having had decision rules in both the 2020 ISP and the Draft 2022 ISP: see 'Decision rules no longer apply' below. Stage 1 is to complete the early works by approximately 2026, and Stage 2 is to complete implementation by July 2031 (or earlier with additional support, see Section 7.1).

Optimal benefits and timing

The rationale for VNI West being included as part of the ODP is set out step-by-step in Section 6 below, and more extensively in Appendix 6. This is a short summary.

VNI West contributes roughly $1.8 billion of the $24.5 billion in net market benefits delivered by the ODP in the most likely scenario, and delivers value in all scenarios. It will increase access to Snowy 2.0's deep storage and other firming capacity from interstate, support new VRE needed to replace coal-fired generation (particularly in the Murray River and Western Victoria REZs), provide greater system resilience to earlier than projected coal closures, secure the fuel cost savings of needing less gas for generation, and reduce VRE curtailment by sharing geographically diverse VRE.

The optimal timing for delivery of VNI West was explored through multiple CDPs. In *Step Change*, it would be needed by July 2031. Making the project actionable now increases insurance against the potential of earlier-than-anticipated coal closures (other than Yallourn) or delays in the delivery of transmission or dispatchable resources.

For VNI West as in other staged projects, the early works costs are incurred early and the benefits potentially accrued later in scenarios where the project is paused. This makes staging particularly sensitive to higher discount rates (see Section 6.4).

Identified need

The identified need for the VNI West project has not changed since the 2020 ISP or Draft 2022 ISP:

> *To increase 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 aging generator reliability – including mitigation of the risk that existing 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, and*
> - *enabling more efficient sharing of resources between NEM regions.*

Next steps

VNI West was determined to be an actionable ISP project in the 2020 ISP and Draft 2022 ISP, and the RIT-T for this project has been initiated. The following parameters apply for the VNI West project:

- **The RIT-T proponent**: AEMO (Victorian Planner) and Transgrid.

- **Scenarios to be assessed**: *Step Change* (52%), *Progressive Change* (30%) and *Hydrogen Superpower* (18%) – AEMO has not included the *Slow Change* scenario because it carries a low likelihood (4%) and the optimal timing is similar to the *Progressive Change* scenario.
- **ISP candidate options** that must be assessed in the RIT-T: AEMO identifies one option (VNI West via Kerang) to be delivered in two stages – early works, then implementation. The technical specifications of this option are provided in Appendix 5.
- **Non-network options** were not assessed in this ISP but are currently being assessed as part of the RIT-T.
- **Decision rules no longer apply:** The decision rules that were outlined in the Draft 2022 ISP have been removed for the VNI West project. After considering stakeholder feedback, AEMO now considers that decision rules should only apply when they can be very clearly defined (for example, a known policy being legislated or a specific power station announcing its closure). Project implementation (stage 2) remains subject to the ISP feedback loop, which will assess whether the project remains aligned with the latest ISP prior to final investment decision.

  Importantly, removal of the decision rules defined in the Draft 2022 ISP that would trigger the progression of stage 2 do not reduce consumer protections against over-investment. The satisfaction of VNI West's Draft 2022 ISP decision rules would simply have allowed a feedback loop for stage 2 to be requested. The feedback loop assessment itself comprehensively tests alignment with the ODP, including by re-running the ISP modelling if necessary, by considering multiple complex interactions that are unable to be captured within decision rules.
- **Early works** for VNI West may include:
  - **Project initiation** – scope, team mobilisation, service procurement.
  - **Stakeholder engagement** – with local communities, landowners and other stakeholders.
  - **Land-use planning** – identify and obtain all primary planning and environmental approvals, route identification, field surveys, geotechnical investigations, substation site selection and easement acquisition.
  - **Detailed engineering design** – transmission line, structure and substation design, detailed engineering design and planning.
  - **Cost estimation** – finalisation, including quotes for primary and secondary plant.
  - **Strategic network investment** – an uplift to the delivered capacity of PEC between Dinawan and Wagga Wagga[71].

[71] The Commonwealth Government has underwritten funds to build a component of PEC at a larger capacity such that it removes the need to duplicate lines for VNI West when it is constructed. See https://www.minister.industry.gov.au/ministers/taylor/media-releases/government-supporting-delivery-critical-transmission-infrastructure-southwest-nsw.

5.5 Future ISP projects

The future ISP projects are identified in Table 7 below, and further detailed in Appendix 5. The dates shown are the earliest feasible timing as well as the optimal timing in the most likely scenario. The timings are indicative, as the actual timing will depend on which scenario unfolds in future.

These projects will deliver net market benefits to consumers but, as they are not needed until later in the horizon, a RIT-T has not yet been initiated for them. This gives time to start planning and engaging with communities now, to ensure the projects optimise long-term benefits for consumers. Future ISP projects are expected to evolve from one ISP to the next.

Table 7 Future ISP projects in the optimal development path†

Project	Timing in most likely scenario	Earliest delivery date	Description
Central to Southern QLD	Stage 1: 2028-29	2025-26	The 2020 ISP triggered preparatory activities to explore options to expand the Central Queensland to Southern Queensland flow path (CQ-SQ). ISP modelling identified two stages to incrementally expand transmission capacity across this CQ-SQ. This first stage involves a new mid-point switching substation on the Calvale –Halys 275 kV double-circuit line, to increase transfer capacity in both directions by approximately 300 MW. Cost: $55 million
	Stage 2: 2038-39	2027-28	A new double-circuit line from Calvale to Wandoan South, to increase transfer capacity to Southern QLD by approximately 900 MW. Cost: $476 million
Darling Downs REZ Expansion	Stage 1: 2028-29	2025-26	A transformer upgrade at Middle Ridge in combination with non-network solutions to lift the capacity of the Darling Downs REZ by approximately 800 MW. Cost: $43 million + BESS contract cost
	Stage 2: 2037-38	2029-30	Targeted 500 kV network expansion across Darling Downs to increase the network capacity of this REZ by 2,500 MW. Cost: $1,160 million
South East SA REZ Expansion	2029-30	2025-26	Incremental network augmentations to expand the capacity of the South East SA REZ by approximately 600 MW. Cost: $57 million
Gladstone Grid Reinforcement	2030-31	2027-28	The 2020 ISP triggered preparatory activities to explore options to supply the Gladstone area following the closure of Gladstone Power Station. ISP modelling has indicated that a 275 kV double-circuit network solution is likely to be the most economic solution to meet this ongoing need. The timing of this project is linked to the continued commercial operation of the Gladstone Power Station. To enable ongoing supply to the Gladstone area following the closure of Gladstone Power Station and increased generation in North Queensland. Cost: $408 million
QNI Connect	2032-33	2028-29	Modelling indicates that this project is optimal in 2032-33 in *Step Change*. This timing is sufficiently later than the earliest feasible timing such that it is not necessary to action now. QNI Connect enables approximately 1,000 MW transfer capacity between southern Queensland and New England, following development of the New England REZ Transmission Link. Cost: $1,253 million
Facilitating Power to Central QLD	2033-34	2029-30	Two new 275 kV circuits between Bouldercombe and Stanwell to increase the transfer capacity from North to Central Queensland by approximately 400 MW. Cost: $137 million
South West Victoria REZ Expansion	2033-34	2029-30	New 500 kV network into South West Victoria can increase the capacity of the REZ by approximately 1,500 MW. Cost: $930 million
Mid North South Australia REZ expansion	2033-34	2029-30	275 kV double-circuit lines between Robertstown, Templers West and Para

Project	Timing in most likely scenario	Earliest delivery date	Description
New England REZ Extension	2035-36	2031-32	Following the establishment of the New England REZ Transmission Link (see Section 5.4), a subsequent expansion of network capacity is required in all scenarios – ranging from 2031-32 to 2045-46. This project enables approximately 5,820 MW of additional export from New England to major load centres around Sydney, following development of the New England REZ Transmission Link. Cost: $3,142 million
Far North QLD REZ Expansion	2038-39	2029-30	Targeted 275 kV network upgrades between Cairns and Townsville to increase the network capacity of Far North Queensland REZ by approximately 945 MW. Cost: $1,264 million

†Additional projects to expand REZs and upgrade flow paths after 2040 are highly uncertain, vary significantly between scenarios, and are not shown in this table. See Appendix 5 for more information.

6 Determining the Optimal Development Path

This section sets out how and why AEMO has determined the ODP, in accordance with the NER, the AER's Cost Benefit Analysis Guidelines and the *ISP Methodology*.

The *ISP Methodology* sets out a six-step cost-benefit analysis, through which AEMO has identified and compared a shortlist of 13 candidate development paths (CDPs) from over 1,000 potential paths, including a counterfactual that has no new network developments beyond those already committed or anticipated.

Each step in this analysis offers AEMO insights with which to determine the ODP, taking into account consumer risk preferences and the resilience of the ODP to those risks through to 2050. AEMO is not bound to adopt the outcomes of any one or more of those steps, but is bound to set out its rationale transparently, as this section provides.

As noted in Section 2, each step of the methodology was completed exhaustively for the Draft ISP. AEMO has since considered any changes to inputs and assumptions in response to stakeholder feedback, changed market conditions, and announced government policies. This has led tore-running some (but not all) of the modelling performed for the Draft ISP, depending on whether there was a possibility of a material impact on the ODP selection.

Accordingly, the rationale for determining the ODP is set out as follows, noting the modelling underpinning the first two steps has not been updated since the Draft ISP:

- **Section 6.1 – Determine the least-cost development paths for each scenario** (Step 1 in the ISP Methodology), which established that all the major network investments have positive net market benefits, so that the only question was 'when' they were needed, not 'if'.
- **Section 6.2 – Build additional CDPs** (Step 2) to assess the risk of under- or over-investment by delivering network projects either too early or too late, to assess the value of staging projects with early works to mitigate against those risks, and to test potential project-related decisions that may affect the outcomes.

The modelling which supports the remaining steps has been selectively updated since the Draft ISP, to the extent indicated throughout this section:

- **Section 6.3 – Assess, rank and evaluate the CDPs** (Steps 3 to 5) using the scenario-weighted net market benefits and least-worst regrets approaches, drawing insights from those approaches. Re-modelling of the CDPs since the Draft ISP has focused on the three major actionable projects whose optimal timing was identified in the Draft ISP as the most uncertain, for the most likely *Step Change* scenario (unless all scenarios are needed for specific CDP comparisons).
- **Section 6.4 – Assess the insurance and option values of bringing potentially actionable projects forward** (part of Step 5). This additional step was taken in the Draft ISP given how close some CDPs ranked in both the net market benefits and least-worst regrets approaches. Some of this analysis has been updated since the Draft ISP, with no change to the conclusion.
- **Section 6.5 – Test shortlisted CDPs through sensitivity analyses** (Step 6) against variations in input assumptions that may affect the outcomes. Some analyses have been updated since the Draft ISP to changed inputs, while others have been added due to new potential policies or market realities.

- **Section 6.6 – Confirming the ODP through an integrated consideration of all CDP analyses**, including market and policy developments since the Draft ISP.

Appendix 6 provides a more detailed description of how the least-cost development paths were developed, an assessment of alternate credible though rejected options, and additional quantitative detail which underpins this section's rationale for the ODP.

Events since the Draft ISP leading to additional analysis

As discussed in Section 2, there have been a number of developments since the Draft ISP which have been taken into account in finalising the ODP. The possible impact of these events on the selection of the ODP is discussed in Sections 6.3 to 6.6.

- **Seventy-eight submissions on the Draft ISP and its Addendum**, resulting in changes to input assumptions, additional sensitivity analysis, and further consideration of various risks and uncertainties. The submissions also influenced how some of the outcomes of the ISP are now communicated, in this report and in the accompanying appendices. AEMO has also updated the earliest entry year for Marinus Link after feedback from TasNetworks, and separately considered the impact of the higher project cost. AEMO's response to all submissions are detailed in the *2022 ISP Consultation Summary Report*.
- **Several market developments** led AEMO to revise input assumptions and sensitivity analyses. Most notable is the announced potential closure of Eraring Power Station in 2025, and the bringing forward of closures of the Bayswater and Loy Yang A power stations (to 2033 and 2045 respectively). Though these accelerated closures are broadly in line with the *Step Change* scenario in the Draft ISP, inputs have been refined to match the revised announcements. Updated assumptions have also reflected an acceleration of committed generation capacity, and further sensitivity analysis has been performed on lower distributed storage uptake, and low discount rates.
- **Potential changes to government policy,** the most notable of which is the Victorian Government's offshore wind directions paper[72]. This led to additional sensitivity analysis to understand the potential impact of significant deployment of offshore wind in Victoria, as well as faster capital cost reductions.

AEMO has considered these further factors in determining the ODP, across Steps 3-5 (as outlined previously) and Step 6 (as outlined above, in applying the additional sensitivity analysis). The additional analysis has focused on the various timing options of HumeLink, Marinus Link and VNI West in the most likely *Step Change* scenario, but includes all scenarios where required for specific CDP comparisons.

6.1 The least-cost path for each scenario (Step 1), from Draft ISP

The least-cost development path in each scenario leverages the geographic diversity of renewable resources and demand, ensures that generation and storage would be used efficiently, and ensures that carbon-emitting fuel sources such as gas are available when needed, but used sparingly in light of their high cost.

Each scenario varies in the timing of network augmentations, which depend heavily on the timing of coal-fired generation withdrawals. Three sets of projects are considered, as shown in Table 8:

[72] Victorian Government. *Victorian Offshore Wind Policy Directions Paper*, at https://www.energy.vic.gov.au/renewable-energy/offshore-wind.

- **Projects needed by 2027-28 or as soon as possible.** The Sydney Ring and New England REZ Transmission Link projects are "low regret" investments, needed early in all scenarios to provide an efficient response to known future conditions, and resilience to likely future challenges. They are now actionable New South Wales projects, to be assessed under the *Electricity Infrastructure Investment Act 2020* (NSW).
- **Projects for which timing needs to be decided urgently.** The optimal timing for three nationally strategic projects – VNI West, HumeLink and Marinus Link – depend on the pace of the NEM's transition. The earlier that coal-fired generation retires, the earlier these projects are needed, so early delivery provides protection against earlier than expected retirements. Early delivery can also offer additional resilience against short-term outages of generation or infrastructure.
- **Projects needed from 2028-29.** The Central to Southern Queensland Reinforcement, Gladstone Grid Reinforcement, QNI Connect and New England REZ Extension projects are not needed immediately, but will be important as the energy system continues to transform in the near future. Given their lead times, they can be deferred for continued analysis, and so are future ISP projects in all CDPs.

Table 8 Optimal timing of major network projects in each scenario, assuming perfect foresight

Project	Earliest Commissioning Date	*Slow Change*	*Progressive Change*	*Step Change*	*Hydrogen Superpower*
Sydney Ring	2027-28	2039-40	2027-28	2027-28	2027-28
New England REZ Transmission Link	2027-28	2027-28	2027-28	2027-28	2027-28
HumeLink	2026-27	2037-38	2035-36	2028-29	2027-28
Marinus Link (Cable 1)	2029-30	2034-35	2030-31	2029-30	2029-30
Marinus Link (Cable 2)	2031-32	2037-38	2032-33	2031-32	2031-32
VNI West	2030-31	2040-41	2038-39	2031-32	2030-31
Gladstone Grid Reinforcement	2027-28	Not needed	2035-36	2030-31	2028-29
CQ – SQ Stage 1	2025-26	2040-41	2030-31	2028-29	2028-29
QNI Connect	2028-29	2035-36	2036-37	2032-33	2029-30
New England REZ Extension	2031-32	2045-46	2038-39	2035-36	2031-32

Note: Green shading shows those projects that would be optimally delivered in line with the earliest commissioning date, or one year delayed. Pink shading shows those projects that would likely be re-assessed as actionable at the 2024 ISP, being within 2-3 years of the earliest commissioning date and assuming no risk of schedule slippage. AEMO is continuing to work with project proponents to re-assess the earliest commissioning timings and any options available to expedite individual projects.

6.2 Candidate development paths to assess risks of investment too early or too late (Step 2, from Draft ISP)

Based on the timings noted in Table 8 above, progressing all projects now could lead to the regret of over-investment if in the slower *Progressive Change* or *Slow Change* scenarios. However, delaying progress would lead to more expensive alternatives to meet the carbon budgets in the *Step Change* or *Hydrogen Superpower* scenarios.

To explore these and similar risks, AEMO created a number of CDPs with different timings for potentially actionable and future projects. In all, over 1000 unique development paths were tested across the scenario collection, designed to assess:

- which least-cost development path performed best across all scenarios,
- the impact on CDP benefits if projects were delayed,
- the impact on CDP benefits if one or more projects were omitted, and
- the option value of staging projects so that they may be paused at an appropriate future project checkpoint prior to final investment decision.

Table 9 below shows 13 of the CDPs that were assessed in the most detail. CDPs 1 to 4 are the least-cost development path in each scenario. Other CDPs then test the addition, removal or staging of potentially actionable projects (for example, CDP5 adds Marinus Link to CDP 1). Other network options may then be optimised as future projects.

Table 9 The candidate development paths (unchanged from the Draft ISP)

In these CDPs …		… these projects would be actionable					
		New England REZ Transmission Link	Sydney Ring	Marinus Link	VNI West	HumeLink	Gladstone Grid Reinforcement
Least-cost CDPs in each scenario							
1	Progressive Change least-cost	✓	✓				
2	Step Change least-cost	✓	✓	✓	✓		
3	Hydrogen Superpower least-cost	✓	✓	✓	✓	✓	✓
4	Slow Change least-cost	✓					
Testing variations to test timing of project delivery and/or event-driven scenarios							
5	CDP1, adding Marinus Link	✓	✓	✓			
6	CDP1, adding VNI West	✓	✓		✓		
7	CDP1, without New England		✓				
8	CDP2, adding HumeLink	✓	✓	✓	✓	✓	
9	No actionable projects						
Testing the staging projects with early works							
10	CDP5, with VNI West staged	✓	✓	✓	✓ Staged		
11	CDP8, with VNI West staged	✓	✓	✓	✓ Staged	✓	
12 (ODP)	CDP10, with HumeLink staged	✓	✓	✓	✓ Staged	✓ Staged	
13	CDP12, removing Marinus Link	✓	✓	✗ Never available	✓ Staged	✓ Staged	

6.3 Assess, evaluate and rank candidate development paths

(Steps 3-5, updated from Draft ISP where most relevant to the ODP selection)

For each scenario, AEMO assessed the net market benefits of the CDPs, then ranked them in the two ways detailed in the *ISP Methodology*:

- **Approach A:** The (mandatory) 'scenario-weighted' average approach, and
- **Approach B:** AEMO's additional 'least-worst weighted regrets' approach.

These approaches, described in detail in the Draft 2022 ISP, highlight what may be an asymmetry between benefits and risks: some CDPs may have higher net market benefits (in approach A) but expose consumers to greater regret costs (in approach B), and vice versa.

6.3.1 Approach A – scenario-weighted net market benefits

In Approach A, the net market benefit of the CDP in each scenario is multiplied by the scenario's weighting (its likelihood as determined through the Delphi process, see section 2.3), and then aggregated.

This section lays out the results of our modelling both for the Draft ISP, and as re-modelled for updated inputs and assumptions for the final 2022 ISP:

- First, Table 10 re-publishes the net market benefits of each CDP across the scenarios, and as a weighted average, as modelled for the Draft ISP. This identified CDP10 and CDP12 as the top ranked candidates in the Draft ISP.
- AEMO then re-modelled most of the CDPs, using the updated inputs and assumptions, for the most likely *Step Change* scenario only. Table 11 sets out the results, and shows that there was no change in the relative net market benefits of the top three candidates (including CDP2).
- Finally, AEMO re-modelled just the top two candidates CDP10 and CDP12 across all scenarios, to see if the updated inputs and assumptions had changed their scenario-weighted net market benefits. The results in Table 12 shows how the gap in net market benefits closed between the two candidates.

Table 10 Weighted net market benefits of CDPs across scenarios for the Draft ISP ($ billion)

CDP	Description	*Slow Change*	*Progressive Change*	*Step Change*	*Hydrogen Superpower*	Weighted Net Market Benefits	Rank
	Scenario weighting	**4%**	**29%**	**50%**	**17%**		
10	CDP5, with VNI West staged*	3.52	16.35	25.59	70.01	29.58	1
12 (ODP)	CDP10, with HumeLink staged	3.35	16.20	25.59	70.20	29.56	2
2	Step Change least-cost	3.25	16.26	25.59	70.01	29.54	3
5	CDP1, adding Marinus Link	3.71	16.51	25.51	69.60	29.52	4
6	CDP1, adding VNI West	3.62	16.47	25.59	69.37	29.51	5
1	Progressive Change least-cost	4.17	16.72	25.50	68.95	29.49	6
7	CDP1, without New England	3.94	16.67	25.49	68.45	29.37	7

CDP	Description	*Slow Change*	*Progressive Change*	*Step Change*	*Hydrogen Superpower*	Weighted Net Market Benefits	Rank
4	*Slow Change* least-cost	4.34	16.50	25.41	68.73	29.35	8
11	CDP8, with VNI West staged	3.13	15.66	25.39	70.20	29.30	9
8	CDP2, adding HumeLink	2.87	15.56	25.39	70.20	29.26	10
3	*Hydrogen Superpower* least-cost	2.51	15.47	25.34	70.53	29.25	11
9	No actionable projects	4.05	16.36	25.28	68.33	29.16	12
13	CDP12, removing Marinus Link	2.19	13.54	20.96	64.50	25.46	13

Table 11 CDP performance for *Step Change*: Draft ISP compared with updated inputs for Final ISP (net market benefits (NMB), $ billions)

<table>
<tr><th rowspan="2">CDP</th><th rowspan="2">Description</th><th colspan="2">Draft ISP</th><th colspan="2">Updated inputs sensitivity</th></tr>
<tr><th>Rank</th><th>NMB relative to top rank</th><th>NMB rank</th><th>NMB relative to top rank</th></tr>
<tr><td>2</td><td>Step Change least-cost</td><td rowspan="3">=1</td><td rowspan="3">-</td><td rowspan="3">=1</td><td rowspan="3">-</td></tr>
<tr><td>10</td><td>CDP5, with VNI West staged</td></tr>
<tr><td>12</td><td>CDP10, with HumeLink staged</td></tr>
<tr><td>6</td><td>CDP1, adding VNI West</td><td>4</td><td>0.008</td><td>5</td><td>0.086</td></tr>
<tr><td>5</td><td>CDP1, adding Marinus</td><td>5</td><td>0.083</td><td>4</td><td>0.026</td></tr>
<tr><td>8</td><td>CDP2, adding HumeLink</td><td rowspan="2">=6</td><td rowspan="2">0.201</td><td rowspan="2">=6</td><td rowspan="2">0.183</td></tr>
<tr><td>11</td><td>CDP8, with VNI West staged</td></tr>
<tr><td>9</td><td>No actionable projects</td><td>8</td><td>0.316</td><td>8</td><td>0.455</td></tr>
</table>

Note: The benefits of projects with staging do not vary in this table because the analysis reflects the fixed timing for the Step Change scenario.

Table 12 Gap in net market benefits from CDP10 to CDP12 ($million)

	Slow Change	*Progressive Change*	*Step Change*	*Hydrogen Superpower*	Weighted
Draft ISP	-166	-149	0	184	-19
Updated inputs	0[73]	-130	0	202	-3

Insights from Approach A analysis and updated inputs

The major insights from this approach, from either the Draft ISP (Table 10) or with updated inputs where available (Table 11 and Table 12), are noted below.

- All the higher ranking CDPs featured the **New England REZ Transmission Link** and **Sydney Ring** project at an actionable timing. These are both projects with minimal regret.
- Staging **VNI West** (CDP10) would deliver an additional $40 million of option value when compared to proceeding with an actionable VNI West without staging (CDP2), on a scenario-weighted basis (Table 9), which itself delivers $20 million net market benefit compared to delaying VNI West (CDP5).

[73] Modelled with updated inputs, the optimal timing of HumeLink in *Slow Change* shifts to 2028-29 (from 2037-38 as in the Draft ISP), and therefore incurs no additional costs in CDP12.

- CDP12, with **HumeLink** as an actionable, staged project, delivers only $3 million less weighted net market benefits than CDP10. (This gap has closed by $16 million with the updated inputs: see Table 12)
- **Marinus Link** as actionable is included in all the higher ranking CDPs, with its benefits largely unaffected by the delivery schedule of VNI West.

Further analysis on the possibility of **MarinusLink** not progressing is detailed in Appendix 6, with the following results:

- Without Marinus Link, progressing VNI West as soon as possible (CDP2) would be $175 million more beneficial than waiting and reassessing in the 2024 ISP (CDP5). The ODP's staging of VNI West would provide appropriate insurance to this risk, enabling the delivery of the project as soon as possible in this circumstance.
- If Marinus Link is not progressed at all (CDP13), there would be a substantial reduction in net market benefits. The updated analysis since the Draft ISP has further improved the case for an actionable Marinus Link, primarily due to the two-year delay in the earliest in-service date, lowering the potential regret associated with early investment in some scenarios. This effect more than offsets the impact of the higher project cost.

6.3.2 Approach B – least-worst regrets approach

The second approach adopted by AEMO is to identify the CDP that would cause the least under- or over-investment regret in any particular scenario. Consumers may regret over-investing if conditions no longer require these assets as quickly, and may regret under-investment if disruption occurs faster than anticipated and the asset is needed sooner than planned. The results of this analysis for the 13 featured CDPs are set out in Table 13. There is no change to this analysis from the Draft ISP.

Table 13 Regret cost of candidate development paths across scenarios, as per the Draft ISP 2022 ($ billion)

CDP	Description	*Slow Change*	*Progressive Change*	*Step Change*	*Hydrogen Superpower*	Weighted worst regret	Rank
	Scenario weighting	**4%**	**29%**	**50%**	**17%**		
10	CDP5, with VNI West staged	0.82	0.37	0.00	0.52	0.11	1
2	*Step Change* least-cost	1.09	0.46	0.00	0.52	0.13	2
12 (ODP)	CDP10, with HumeLink staged	0.99	0.52	0.00	0.34	0.15	3
5	CDP1, adding Marinus Link	0.63	0.21	0.08	0.94	0.16	4
6	CDP1, adding VNI West	0.72	0.25	0.01	1.16	0.20	5
1	*Progressive Change* least-cost	0.17	0.00	0.09	1.59	0.27	6
11	CDP8, with VNI West staged	1.22	1.05	0.20	0.34	0.31	7
4	*Slow Change* least-cost	0.00	0.22	0.18	1.80	0.31	8
8	CDP2, adding HumeLink	1.47	1.16	0.20	0.34	0.34	9
7	CDP1, without New England	0.40	0.04	0.11	2.08	0.35	10
3	*Hydrogen Superpower* least-cost	1.83	1.24	0.25	0.00	0.36	11
9	No actionable projects	0.29	0.35	0.32	2.21	0.38	12
13	CDP12, removing Marinus Link	2.15	3.18	4.63	6.04	2.32	13

The "weighted worst regret" shown in this table represents the maximum regret observed across the scenarios, after the individual scenario regrets are weighted using the scenario weightings at the top of the table. The regrets for each scenario (the first four columns) are provided unweighted.

Insights from Approach B analysis

Overall, the insights from Approach B align with those from Approach A, and confirm the asymmetry of risk that the risk of delaying investment is greater than that of investing early:

- The regrets in the most likely *Step Change* scenario are negligible for the top three CDPs.
- Progressing Marinus Link now (CDP5) would lower the worst-weighted regrets by $110 million.
- Actioning VNI West with staging helps to minimise weighted worst regret (CDP10 vs CDP 5).
- Delaying investment in HumeLink would lead to approximately $40 million less weighted regrets than staged actionable development, all else being equal (CDP10 vs CDP12).

6.4 Testing the insurance and option value of project timing

Both approaches of the cost-benefit analysis confirm the benefits of all the potentially actionable projects being considered in the ODP. However, further sensitivity analysis has been conducted to explore differences in the potential benefits of the ODP to provide insurance against plausible risks, while retaining option value to protect consumers and pause a project if later assessed to be delayed at the next relevant project milestone (for example, in feedback loops).

While staging may provide an opportunity to improve the design of the project and reduce uncertainty around cost estimates (ideally bringing project costs down), staging may lead to spending money earlier than otherwise needed, having to re-incur expenses (in a paused project), or writing off incurred costs (in an abandoned project). Therefore, the option and insurance values need to exceed these costs, and/or reflect consumer risk preferences.

This analysis can be completed for all staged projects, given project staging by nature provides potential option value. AEMO used HumeLink as the case in point, as its treatment is the only difference between CDP10 and CDP12. There are only marginal differences in the potential benefits and regrets between delaying it (CDP10) and including it as an actionable staged ISP project (CDP12). Applying equivalent sensitivity analysis to CDP5 and CDP10 would demonstrate similar insights for VNI West, for example. This has not been performed given that actioning VNI West (CDP2) provides greater net market benefits than delaying the project (CDP5).

6.4.1 Insurance against schedule slippage risks

The first analysis considers the risk of delays from both securing social licence for major generation, storage and transmission projects, and from supply chain shortages through the development.

The need to secure social licence

The ISP shows how the NEM can secure affordable and reliable energy for consumers within the modelled emission constraints. However, even with multi-purpose land use, the land needed for major VRE, storage and transmission projects to realise these goals is not insignificant. While land needed for network easements will be much smaller than that required for VRE, their long, linear routes are likely to affect more landholders.

There is a risk of schedule slippage if landholder, First Nation, conservation and other stakeholder groups withhold social licence for the projects until issues are resolved with broad community acceptance. Although project staging and funding for early works may help address some timing and cost uncertainties, uncertainty regarding the extent and timing of social licence cost recovery remains. Many jurisdictions are now taking an integrated land use planning approach that will support the delivery of broader decarbonisation objectives.

While the sector is taking steps to mitigate these risks (see Section 7.3 below), its impact must be taken into account in the determination of the ODP.

The need to manage supply chains

The worldwide growth in renewable energy over the next three decades, spurred by 2030 and 2050 emissions targets, will significantly increase demand for labour, expertise, materials and specialised electrical equipment. Bottlenecks in any one supply sector could impact delivery of the many significant projects in the ODP forecast for the late 2020s and, if those projects slide, they risk competing for skills and materials with further projects slated for the 2030s, domestically and globally.

Managing these supply-side constraints is paramount for the effective and timely completion of the NEM's infrastructure roadmap. Infrastructure Australia's recent Market Capacity Report[74] found that infrastructure projects face an expected shortfall of infrastructure-connected labour of over 105,000 roles in mid-2023, and that up to 40% of the infrastructure workforce is expected to retire over the next 15 years, without the population growth needed to replenish it. In the energy sector, a separate Infrastructure Australia initiative[75] found that between 80,000 and 95,000 people would be needed over the next 15 years in a variety of roles, primarily for large-scale renewable energy. Skill shortages would likely be exacerbated by any peaks and troughs in construction, competition between states and regions, and by a lack of diversity in projects. The initiative also forecast that demand for steel from the electricity sector (NEM-wide) would increase by ~50% from 2021 to 2027, and that demand for concrete would double.

The ODP helps participants to manage the supply chain by increasing certainty on when project deliveries are needed. However, the regulated process is not designed to provide comprehensive sequencing between and within projects, and it will be up to NEM participants and network service providers to continue working to ensure a smooth and sequenced construction schedule: see Section 7.4. In the meantime, the risk of delays must be considered as a plausible risk, and therefore appropriate to influence the selection of the ODP.

Providing insurance against slippage risks

Insurance against the risk of delays can be achieved by bringing forward a project's starting date, either with or without a later staging decision. The decision tree in Figure 31 below shows the relative values of these three options, in the case of HumeLink, represented by the three CDPs that differ only by the project's timing.

The net market benefits at the beginning of each branch are from the right-hand column of Table 10.[76] In CDP 10, HumeLink would only become actionable in the 2024 ISP (or later). If it is then delivered on time, CDP 10 would deliver a net benefit to consumers just $3 million more than CDP 12 ($27.742 billion relative to $27.738 billion). If instead there is a two-year schedule slippage, the net benefit falls by $130 million if the

[74] See https://www.infrastructureaustralia.gov.au/publications/2021-infrastructure-market-capacity-report, 13 October 2021.

[75] Infrastructure Australia, Market capacity for electricity generation and transmission projects, October 2021, at https://www.infrastructureaustralia.gov.au/sites/default/files/2021-10/Market%20Capacity%20for%20Electricity%20Infrastructure%20211013.pdf., studying labour and material requirements to fulfil the NEM-wide generation and transmission projects included in the 2020 ISP, updated with revised assumptions for the Draft 2022 ISP scenarios.

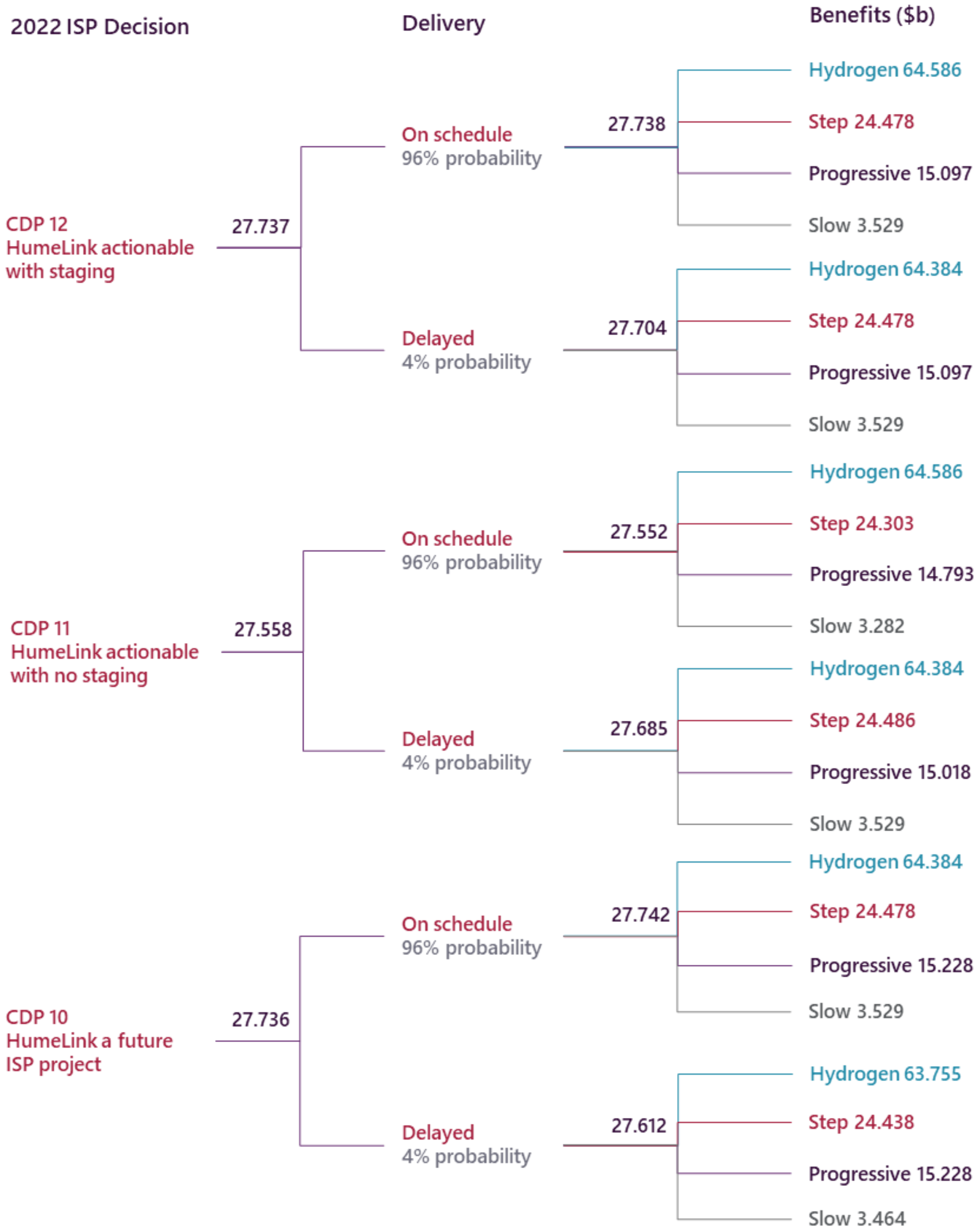
[76] To simplify the calculation, it is assumed that a decision made now cannot predict the scenario that is playing out, whereas in two years' time it can. In reality, there will still be uncertainty.

project was initially delayed (CDP10), to $27.612 billion -- $90 million less than delivering a staged, actionable project now (CDP 12).

For CDP12's benefits to exceed CDP10, the risk of schedule slippage by two years would need to be 4% or greater for that branch of the decision tree to demonstrate greater benefits than CDP10. Given the recent history of progressing major NEM projects, that 4% likelihood of delay is very plausible[77].

The actions that may be needed to protect against delays from the manifestation of social licence and supply chain risks are discussed in Sections 7.3 and 7.4 below.

Figure 31 Option value with HumeLink as a staged project and risk of schedule slippage ($ billion)



[77] Supported by analysis conducted by Independent Project Analysis, Inc on industrial mega projects and large infrastructure projects, available at https://www.ipaglobal.com/news/article/edward-merrow-reveals-why-megaprojects-fail-in-project-manager-magazine-cover-story/.

6.4.2 Insurance against shortfalls in dispatchable supply

Two other risks are material to the ODP assessment. In each scenario, additional transmission would be required should there be earlier coal exits than modelled, or later availability of storage or other dispatchable supply, or both. These events would risk a supply shortfall, and transmission assets may assist to fill this shortfall by enabling increased resource sharing to maintain supply.

Insurance against the risk of further early coal exits

Since the Draft ISP, there have been several well-publicised announcements of early coal closures, most notably the potential early closure of Origin Energy's Eraring Power Station. Although this announcement represents only a slight acceleration in the coal closure trajectory projected in *Step Change* and *Progressive Change* in the Draft ISP, it re-emphasises the potential risks of earlier-than-anticipated coal closures.

That risk is exacerbated by the current 3.5-year notice of closure requirement in the NEM[78], which is too short for transmission development to be accelerated in response to closure announcements. Even a five-year notice period (as in Victoria) is not enough lead time for most major transmission projects if not already progressing. Bringing transmission development forward would therefore help insure against coal closures on such relatively short notice.

AEMO has assessed the insurance value of the earlier development of HumeLink, making it actionable in this ISP targeting a 2026-27 delivery. If it is then available when coal exits, it would provide access to Snowy 2.0 to New South Wales consumers to cover potential generation shortfalls. If it is not, additional storage and/or peaking gas development would be required, even more than the significant investments being made under the NSW Electricity Infrastructure Roadmap. For example, if HumeLink is available when Bayswater closes, an additional 1.3 GW of firming capacity would be avoided, contributing to a net market benefit of $192 million in *Step Change*: see Table 14.

Insurance against that outcome, by making HumeLink actionable (with staging) as part of CDP12, comes at a very small cost. Comparing the scenario-weighted net market benefits with CDP10, with updated inputs, the additional cost in the form of reduced consumer benefits is only $3 million. If there were just a 1% or greater chance of a further coal closure by 2026-27, that insurance would be worth taking (even ignoring the risk of schedule slippage discussed above). As VNI West and Marinus Link are due to be commissioned later than HumeLink, the extent of coal closures by that time is already explored across the scenarios.

Recently, suggestions have emerged of a potential delay to the delivery schedule of Snowy 2.0[79], which would reduce the reserves available to New South Wales consumers when HumeLink is commissioned. However, HumeLink will also improve access for consumers to stored energy across the entire Snowy scheme, to renewable energy in southern New South Wales, and to imports from South Australia (via Project EnergyConnect) and Victoria (via VNI and VNI West). If it is delivered earlier than is needed for Snowy 2.0, it will still be delivering its market benefits, and its timely delivery will still provide greater resilience to the risks schedule slippage in other generation, storage and transmission investments.

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[78] See https://www.aemc.gov.au/rule-changes/amending-generator-notice-closure-arrangements.

[79] The 2022 ISP modelling does not apply any change to the Snowy 2.0 project's schedule. The CBA within the ISP does not capture this quantitatively.

Table 14 Net market benefits of HumeLink as an actionable ISP project (in 2022 rather than 2024) ($ million)

In this scenario…	If coal generation closes as projected, the benefit of making HumeLink actionable would be …	But if Bayswater closes earlier than projected, the benefit would be …
Step Change	-183	192
Progressive Change	-350	1190

Note: Additional reliability benefits are not included in this comparison. For more detail on these see Appendix 6, section A6.7.3.

Insurance against the risk of further delays in storage development

As coal withdraws over the next decade, system reliability will rely in part on storage that is capable of continuously generating for at least eight hours. For example, to meet the minimum objectives of the New South Wales Roadmap, the 2021 IIO Report calls for 0.6 GW of such storage capacity by 2025-26, and an additional 0.95 GW by 2027-28.

However, the 2021 IIO report recognises that the timing, technology readiness and cost of this deeper storage is subject to a high degree of uncertainty. If it were to be pumped hydro, it is unclear if it could be constructed quickly enough to meet the IIO objectives. Independent to the IIO objectives, the recent suggestions of Snowy 2.0 schedule slippages illustrate the risks that face generation and storage projects.

If storage is delayed, HumeLink and other transmission projects would reduce the risk of supply scarcity for New South Wales consumers. While not explicitly quantified, this risk further supports the option and insurance value of progressing HumeLink as a staged actionable project targeting implementation as soon as possible, and no later than 2028-29.

6.5 Testing the robustness of the candidate development paths (Step 6)

Step 6 of the cost benefit analysis methodology is to explore the robustness of high ranking CDPs to material changes in key assumptions. This analysis tests a range of sensitivities to reveal if they would have any material impact on the selection of the timing of network projects in the ODP, and confirm that they pose no barrier to the leading candidate becoming the ODP.

The results of these analyses are detailed in Appendix 6 and summarised here, both for the sensitivities presented in the Draft ISP, and for additional sensitivities tested since then. The outcomes presented in the Draft ISP were not materially impacted by changes in inputs and assumptions, unless otherwise stated below.

The overall finding is that the high ranking CDPs were generally robust to the sensitivities, the exceptions being the impact of higher discount rates and the influence of removing the TRET.

- **Higher discount rates:** With a 10% discount rate, the highest value deemed appropriate in AEMO's input collection, scenario-weighted net market benefits fell by up to $13.3 billion and the CDP rankings changed materially. Although CDP12's net market benefits were approximately $150 million lower than the highest ranked CDP1, it still delivered positive net market benefits overall, and positive benefits in all scenarios (see discussion below).
- **Lower gas prices:** Although lower gas price assumptions reduced the overall net market benefits of all CDPs by approximately $2.3 billion, there was no change in the ranking of higher ranked CDPs (see discussion below).

- **Stronger electrification:** A *Strong Electrification* sensitivity (with strong emission reduction objectives, but limited hydrogen uptake) had minimal impact on CDP rankings, confirming that the speed of coal withdrawals is the primary driver for transmission investment (see discussion below).
- **Higher installed capacity of distributed PV systems** would preference large-scale wind developments more strongly, but had a minimal impact on CDP rankings.
- **Additional deep storage in Queensland** led to more development of Queensland solar generation, but also had a minimal impact on CDP rankings.
- **Initial storage deployments within the Sydney, Newcastle and Wollongong area** slightly reduced the net market benefits of the Sydney Ring project, but not enough to reduce the urgent need for this project.
- **Removing the influence of TRET** slowed the accumulation of benefits provided by the Marinus Link project. Under these circumstances, the optimal timing of the first Marinus Link cable could have been pushed back up to four years in the *Progressive Change* scenario.

Further sensitivity analyses were performed against the *Step Change* scenario in response to the key market developments, stakeholder feedback and policy developments discussed above:

- **Offshore wind targets** specified in the Victorian Government's Directions Paper, together with greater capital cost reductions for offshore wind generation, resulted in a significant reduction in onshore VRE development. However there was no impact on CDP rankings.
- **Reducing the forecast uptake of and coordination of distributed storage** also had no impact on CDP rankings.
- **A lower discount rate** generally favours CDPs with more accelerated developments, with CDP12 (having the most accelerated developments) becoming the highest ranked when considered across all scenarios.

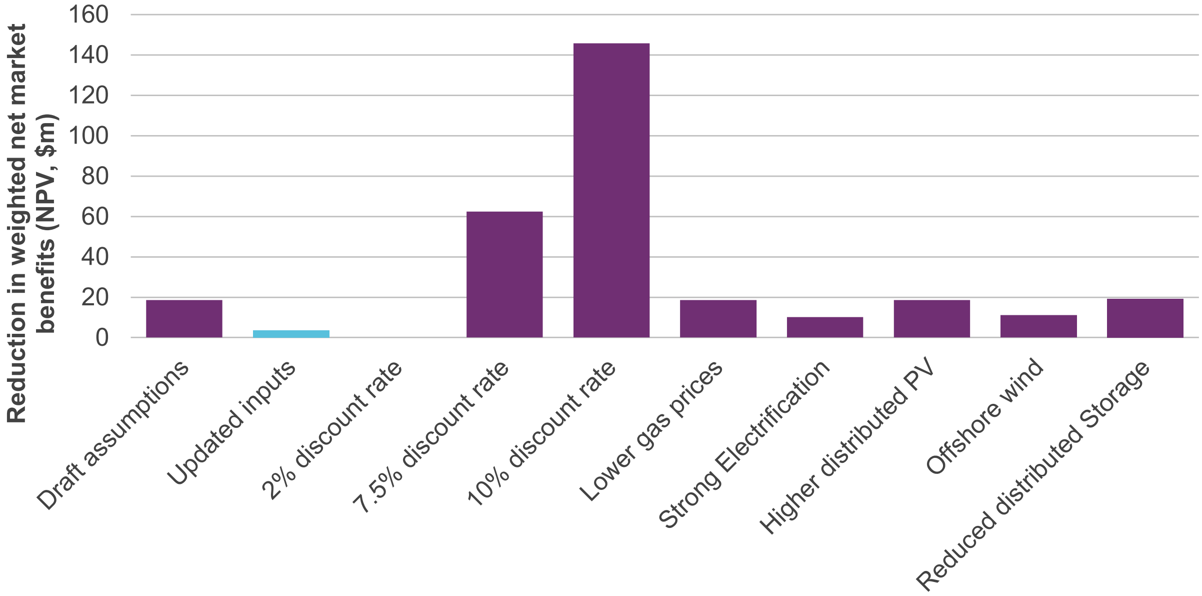
Figure 32[80] shows the impact of varying these assumptions on the scenario-weighted net market benefits of the ODP, compared to the top-weighted CDP within each assessment.

For comparison, the first two values show the difference between the ODP and top-weighted CDP for the assumptions used in the Draft ISP, next to the updated inputs for this final ISP (see Table 12, Section 6.3.1). Following these two, the additional sensitivities (conducted on Draft ISP assumptions) are presented.

In the majority of the sensitivities considered, the ODP remains within $20 million, with the exception of higher discount rates. For the lower 2% discount rate, the ODP is the optimal CDP and there is therefore no difference.

[80] This figure is different to Figure 31 from the Draft ISP which presented the impact of the sensitivities on the benefit of the ODP relative to the counterfactual, rather than comparing to the top-ranked CDP within each sensitivity.

Figure 32 Reduction in weighted net market benefits in ODP relative to top-ranked CDP, by sensitivity



Discount rates

The assumed discount rate for the CBA methodology is 5.5%. AEMO has conducted sensitivity analyses for two higher discount rates identified in the IASR: the upper bound (7.5%) and highest value (10%) rates.

Overall, higher discount rates result in CDPs with more transmission investment falling in the rankings, so the cost of staging or fully actioning HumeLink and VNI West increase with the higher rates. By comparison, lower discount rates (2%) favour CDPs with more accelerated development, which confirms that staging remains a key tool for managing risk of over-investment.

At the 10% discount rate, the rankings of the CDPs changed materially, with CDP1 becoming the highest ranked. CDP12's net market benefits were approximately $150 million lower than CDP1. Nonetheless, CDP12 still delivered positive net market benefits overall, and positive benefits in all scenarios. Given it is robust to all other sensitivities and continues to deliver positive benefits in all scenarios, AEMO does not consider that this sensitivity analysis changes its selection of the ODP.

Lower gas prices

By the end of the forecast period, approximately half of the net market benefits of the ODP derive from the fuel cost savings of avoided gas-fired generation: see Figure 27 in Section 5.1 above. If gas prices fall, so too would these benefits. AEMO has tested the impact of lower gas prices on the higher ranked CDPs with Marinus Link, VNI West and HumeLink. While lower gas prices reduce the net market benefits of all of the CDPs by approximately $2.3 billion, they do not change their ranking as all result in similar reductions in gas consumption.

Recent global energy market dynamics, leading to extremely high global and domestic gas prices, demonstrate that the likelihood of sustained low domestic gas prices are unlikely without significant market intervention domestically. Considering that all CDPs lead to materially less gas use for generation (notwithstanding the significant value provided at times when gas is needed to firm VRE), a sensitivity to higher gas prices has not been conducted.

Stronger electrification

AEMO has modelled a *Strong Electrification* sensitivity that assumes the same emission reduction objectives as *Hydrogen Superpower*, but with limited hydrogen uptake. Stronger and faster electrification of transport and heavy industry is therefore needed to achieve the economy-wide emission reductions.

The modelling suggests that the CDP rankings are relatively robust to this sensitivity. The potential need for early transmission investments is set by the emission reduction objectives and the speed of coal closures, rather than any demand for electricity from hydrogen developments. The transmission investments would be needed to support faster and larger VRE development, and greater storage as coal retires earlier. Additional high-quality renewables such as offshore wind may also be needed in the 2040s in this sensitivity.

6.6 Confirming the Optimal Development Path

The six-step CBA approach provides a comprehensive and collaborative analysis to quantify the net market benefits for consumers for various CDPs. It considers a range of reasonably foreseeable events, risks and sensitivities that may affect the identification of the ODP.

In AEMO's opinion, this analysis confirms CDP12 as the ODP. While the mandatory approach of comparing scenario-weighted net market benefits of the candidates favours CDP10, the gap to CDP12 is extremely small, and is outweighed by further analyses of the insurance and option value of making HumeLink actionable as a staged project in this ISP, rather than wait until the 2024 ISP.

In the mandatory approach, the marginal $19 million gap between CDP12 and CDP10 in the Draft ISP has reduced further with updated inputs to just $3 million, and there is no gap in the most likely *Step Change* scenario: see Table 12 above.

The further analyses of insurance and option value shown in Section 6.4 confirm that CDP12 would better protect the NEM against the risks of early coal closures, or delays in the dispatchable supply or transmission projects intended to replace that coal-fired generation. The value of this protection in avoiding such a supply gap, and maintaining reliable, affordable electricity supply while pushing to net zero emissions, cannot be overstated. The cost of that insurance is negligible (approximately 0.01% of overall net market benefits), and needs only a 4% probability of schedule slippage or a 1% probability of earlier coal closures for it to be worth taking.

The risks associated with a delay (or abandonment) of Marinus Link over funding uncertainty further emphasises the insurance value that the staged VNI West project provides. As with HumeLink, consumer protections to over-investment risks are retained in the ODP through the feedback loop assessments when each project's first stage is complete.

Consumers are seeking to secure the economic and emission benefits of the ODP without over-spending. AEMO believes that taking the insurance of making CDP12 the optimal development path is firmly in line with consumer risk preferences. While those preferences are difficult to quantify, AEMO believes that the insurance value of CDP12 far outweighs its marginal deficit to CDP10 in the initial analysis. It also stresses that both candidates would deliver substantial and long-lasting benefits to the Australian economy and to its achieving net zero emissions by 2050.

7 Implementing the ODP

The pace of change and scale of investment in the coming years is unprecedented in Australia's energy sector, at a time of accelerated investment in other forms of national infrastructure as well as regional responses to the physical threats of climate change. All of the NEM's stakeholders will therefore need to collaborate on a number of fronts to ensure the timely implementation of the ODP. The needed actions include:

- **7.1** Immediate action to progress actionable ISP projects
- **7.2** Preparatory activities and potentially REZ Design Reports for future ISP projects.
- **7.3** Substantially expanded community engagement to build and maintain the social licence for generation and transmission investments
- **7.4** Investment coordination to alleviate supply chain constraints, project costs and timelines
- **7.5** Continued market reforms and distribution network upgrades to unlock the potential of DER, and
- **7.6** Power system engineering to address technical challenges as renewable energy replaces traditional generation.

7.1 Progressing actionable projects

To protect consumers against the risk of over-investment, the ISP process can tend to make an individual project actionable only when the benefits are clear and the project is somewhat urgent. To date, a number of projects have been impacted by supply chain limitations and other factors, resulting in confirmed or potential changes to timing.

All actionable projects should progress as urgently as possible. The delivery dates for actionable projects are largely dictated by their earliest practical delivery time as advised by the project proponents. In some cases, the optimal timing would be earlier than what is achievable; in others any earlier delivery provides valuable insurance against faster-than-expected coal closures or slower-than-expected VRE and storage development. The immediate actions needed to progress actionable projects are set out in Section 5.3.

Mechanisms which support earlier progression of projects can deliver cost savings in construction and earlier realisation of benefits. Those mechanisms are being or are planned to be delivered by the NSW Transmission Acceleration Fund, the Victorian Renewable Energy Development Plan, the Commonwealth Government's Rewiring the Nation Policy and other government policies and approaches.

The Commonwealth Government intends to enable and support this transition with its Rewiring the Nation policy through a range of potential mechanisms, such as changes to the regulatory framework, who pays for the transmission infrastructure, and improved recognition of the impact on landholders and communities hosting the required infrastructure.

7.2 Preparatory activities and REZ Design Reports

The ISP may trigger preparatory activities and REZ Design Reports for future ISP projects, so that sound decisions can be made in their design and planning as early as possible.

- Preparatory activities may be triggered for any future ISP project to improve the assessment in future ISPs. Both Sydney Ring and the New England REZ Transmission Link were future ISP projects in the 2020 ISP and their preparatory activities have assisted in enabling an accelerated status in this ISP.
- REZ Design Reports were included in the NER as recommended by the ESB Review into Renewable Energy Zones, to commence design work on REZs. They go beyond preparatory activities, being intended to explore and report on any technical, economic or social issues that will need to be addressed for the REZ to be a valuable, sustainable and welcome development.

7.2.1 Preparatory activities for future ISP projects

Table 15 below sets out the preparatory activities that are triggered by this ISP for some of the future ISP projects. The work is needed for the effective design of REZ expansions and flow path upgrades, and is to be completed by 30 June 2023.

Table 15 Preparatory activities are required for some future ISP projects

Project	Indicative timing	Responsible TNSP(s)	Preparatory activities required
South East SA REZ expansion (Stage 1)	2025-26 to 2045-49	ElectraNet	AEMO requires that the responsible TNSPs undertake the following preparatory activities by 30 June 2023 for each project listed in this table, including publishing a report on the outcome of these activities: • Preliminary engineering design. • Desktop easement assessment. • Cost estimates based on preliminary engineering design and route selection. • Preliminary assessment of environmental and planning approvals. • Appropriate stakeholder engagement.
Darling Downs REZ Expansion (Stage 1)	2025-26 to 2047-48	Powerlink	
Mid-North SA REZ Expansion	≥ 2028-29	ElectraNet	
QNI Connect (500 kV option)	2029-30 to 2036-37	Powerlink and Transgrid	
QNI Connect (330 kV option – NSW scope)		Transgrid†	
South West Victoria REZ Expansion	≥ 2033-34	AEMO (Victorian Planner)	
Central to Southern Queensland	2028-29 to 2040-41	Powerlink	No action required – AEMO will escalate costs from previous Preparatory Activities.
Gladstone Grid Reinforcement	≥ 2030-31	Powerlink	
QNI Connect (330 kV option – QLD scope)	2029-30 to 2036-37	Powerlink	

† AEMO triggered preparatory activities for Reinforcing Sydney, Newcastle & Wollongong Supply and QNI Connect (NSW scope) in the 2020 ISP for use in the 2022 ISP. Although Transgrid provided AEMO with the preparatory activities reports, the costs were provided on a confidential basis. The ISP regulatory framework is designed to be transparent and consultative for all stakeholders, and AEMO does not consider it appropriate to use confidential transmission costs in the ISP. Accordingly, AEMO used its own estimates for these projects in the 2022 ISP and requests that Transgrid provide the information in a format that can be published.

7.2.2 REZ Design Reports

REZ Design Reports are part of a new framework that goes beyond the scope of preparatory activities, and explore the technical, economic and social barriers to unlocking REZs. AEMO may require a REZ Design Report to be prepared for any REZ transmission extension that is both on the ODP within 12 years of ISP publication and is reasonably considered by AEMO to have the support of the Minister of the relevant jurisdiction[81]. This is a significant investigation, led by the local jurisdictional planning body, involving:

- engineering designs, cost estimates and easement investigations that considers developer and community interest,

[81] NER 5.24.1(a)

- stages that can be delivered to meet capacity targets in the ISP,
- identification of barriers to community acceptance and estimates of costs associated with overcoming them, and
- a draft report and a six-week consultation.

Assuming the relevant government support, AEMO may trigger a REZ design report either in or between ISPs.

AEMO has not called for any REZ design reports in this 2022 ISP, as each jurisdiction has or is developing its own REZ framework:

- **Commonwealth** – The Commonwealth Government regulates offshore wind projects in Australian Commonwealth waters, and have not yet declared whether the REZ design report framework would be used for them[82].
- **New South Wales** – AEMO has not called for REZ design reports in New South Wales because the activities would duplicate work that is being progressed through the New South Wales Government's Electricity Infrastructure Roadmap[83].
- **Queensland** – AEMO is continuing to engage closely with the Queensland government on Queensland's Energy Plan[84], including on whether the REZ design report framework would be relied on.
- **South Australia** – AEMO is continuing to engage closely with the South Australian government on a wide array of initiatives for the development of renewable energy in South Australia, including on whether the REZ design report framework would be relied on[85].
- **Tasmania** – AEMO is continuing to engage closely with the Tasmanian Government on the expected announcement of their first REZ in Q4 2022[86], including on whether the REZ design report framework would be relied on.
- **Victoria** – AEMO has collaborated with the Victorian Government on an initial REZ Development Plan for the full development of Victorian REZs.[87] The Victorian Government has also released an offshore wind development policy and intends to integrate this with its REZ plans. AEMO is engaging with the new government agency VicGrid, including on whether the REZ design report framework would be relied on.

7.3 Securing social licence for VRE, storage and transmission

As discussed in Section 6.4.1, securing community support and appropriate social licence is vital to the timely delivery of essential NEM infrastructure projects. Often landowners and communities are focused on specific transmission projects, with a range of bodies advocating for alternative paths. However, there can be many benefits from early and thorough community engagement that takes a more holistic view of land use and

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[82] Commonwealth Government. *Offshore electricity infrastructure framework: regulations and cost recovery*, at https://consult.industry.gov.au/oeif-regulations-and-cost-recovery.

[83] New South Wales Government. *Renewable Energy Zones*, at https://www.energy.nsw.gov.au/renewables/renewable-energy-zones.

[84] Queensland Government. *Queensland's Energy Plan*, at https://www.epw.qld.gov.au/about/initiatives/cheaper-cleaner-energy.

[85] South Australian Government. *South Australia Growth and Low Carbon*, at https://www.energymining.sa.gov.au/growth_and_low_carbon.

[86] Tasmanian Government. *Renewable Energy Coordination Framework*, at https://recfit.tas.gov.au/renewables/tasmanian_renewable_energy_action_plan.

[87] Victorian Government, *Renewable Energy Zone Development Plan*, at https://www.energy.vic.gov.au/renewable-energy/renewable-energy-zones.

broader economic issues. In some cases, that engagement may lead to alternative developments that reduce the need for new transmission, including storage or other forms of dispatchable capacity and offshore wind developments that connect to the existing network easements.

The ISP seeks to limit the physical footprint of new VRE and transmission development, by concentrating VRE in the REZs and limiting VRE to a proportion of land within an REZ. Even so, VRE developments will tend to be concentrated or clustered in particular areas within the REZ where the network access and/or land use is most suitable. As well, NEM jurisdictions are doing much to identify alternative REZ locations and innovative dual-land-use initiatives that may offer additional revenue opportunity for communities, without being in competition with existing businesses.

While the new REZ Design Report framework is designed to assist these processes, the NEM state and Commonwealth governments are either putting in place or have in place jurisdictional frameworks to design and deliver REZs, and the jurisdictional planning bodies have primary responsibility for managing the development of network infrastructure to support the projected development of new VRE in REZs.

Continuing and expanding the already strong collaboration between generation developers, TNSPs, and NEM jurisdictions will help:

- consolidate an integrated approach to land use planning that optimises multi-purpose land use and aligns with local interests,
- broaden local council, landholder and traditional owner engagement to incorporate broader community and environmental benefits (including regional economic and jobs growth, emission reductions, and biodiversity habitat and corridors),
- systematically document local concerns and incorporate them in the ISP, REZ Design Report, and local planning processes,
- consolidate and align appropriate compensation mechanisms for affected land owners and communities,

  ensure the design of transmission and VRE assets take advantage of available design and technology choices to minimise their impact on land use, and
- harmonise the infrastructure, policies and objectives across jurisdictions.

7.4 Managing supply chains

The delivery timetable of the ODP also partially depends on carefully managing the risk to supply chains of increasing coincident global demand for the same infrastructure expertise, materials and equipment. As discussed in Section 6.4.1, the level of VRE, dispatchable supply and transmission projects is unprecedented for the NEM, and the NEM is not alone in this transition. ISP modelling seeks to schedule projects to deliver the greatest benefits to consumers. However, the ISP process does not currently consider the sequencing of project steps to ensure it is completed within its delivery date while managing global supply chain risks.

To that end, NEM stakeholders will need to collaborate towards a smooth and sequenced construction schedule. A bottleneck affecting one supply sector may risk delivery of the many significant projects in the ODP forecast for the late 2020s and, if those projects slide, they risk competing for skills and materials with further projects slated for the 2030s.

Supply chain projections may be a useful inclusion in future ISP processes. Since the 2020 ISP, AEMO has partnered with Infrastructure Australia and the Institute for Sustainable Futures to better understand the

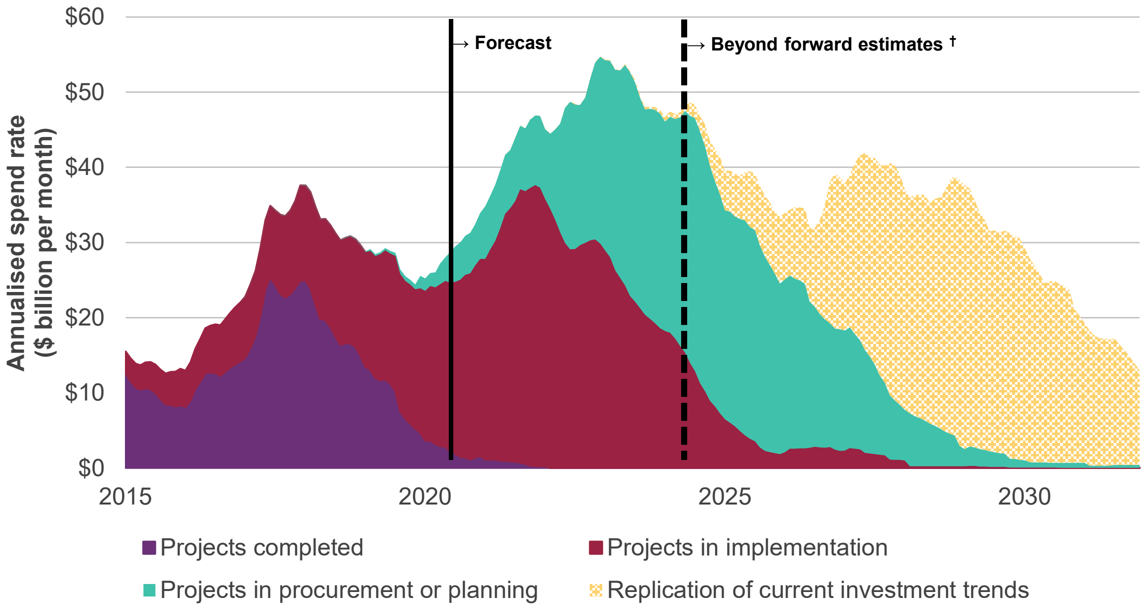
NEM's supply chain needs. This section reviews insights from that and similar work that may assist NEM participants in their future project planning, and suggests that:

- **Deeper understanding of investment pipelines is needed in energy alongside other infrastructure sectors.**
- **Employment needs for renewable energy development** will outpace the employment decline in oil and gas. Transitioning skilled workers into renewable energy would have multiple benefits, including reducing the need to source skilled workers internationally
- **Plant, steel and concrete supply** for renewable energy and transmission will be heavily influenced by domestic and foreign infrastructure projects in transport, construction and other sectors
- **Project sequencing** will improve the likelihood that projects are delivered on time and to budget. Supply capacity for labour and materials will meet a smooth pipeline of ISP infrastructure projects far better than if ISP projects are competing for those resources.

7.4.1 Understanding infrastructure pipelines

Infrastructure costs typically rise with the number of simultaneous projects. A pipeline of infrastructure initiatives to support economic recovery in the aftermath of COVID-19, and to accelerate the energy transition, have added to short-term demand: see Figure 33 (Australian infrastructure spend). Infrastructure Australia projects this rise in demand will test labour, plant and materials markets into the mid-2020s. The domestic and global demand for materials is less certain beyond 2025. While many countries have committed to net zero targets by 2050, there may be a short-term opportunity to advance projects before the global competition for materials increases.

Figure 33 Investment in infrastructure is lumpy and unpredictable



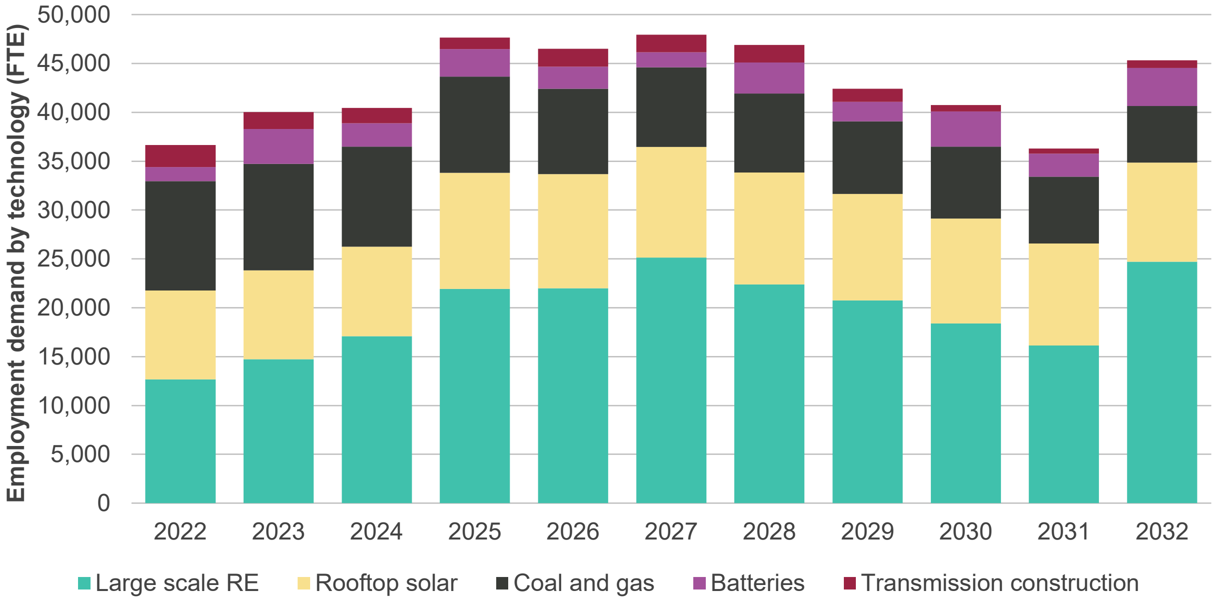
Source: *Infrastructure Australia. Infrastructure Market Capacity (October 2021).*
† Available data for the period beyond forward estimates is limited. Actual spend beyond 2025 will be dependent on future project announcements. The replication of current investment trends demonstrates the spend profile if current spending levels are replicated.

7.4.2 Securing the needed workforce

The *Market Capacity for Electricity Infrastructure*[88] project is developing workforce projections by technology, occupation and location to correspond with ISP scenarios. Demand for skilled labour in large-scale renewable energy is forecast to double from approximately 12,500 in 2022 to 25,000 in 2027: see Figure 34. The growth in the renewables workforce will outpace the decline in the traditional generation workforce, which is forecast to drop by 6,000 or over 50% over the next decade. These dynamics will challenge engineering, procurement and construction (EPC) firms and regional communities as well as individual workers, particularly if there are boom-and-bust cycles, and particularly if most workers and contractors are engaged project-to-project.

Stakeholders and governments will need to collaborate on ways to develop and secure a long-term, reliable supply of workers at every needed level of qualifications and skills.

Figure 34 Forecast labour demand by energy infrastructure sub-sectors



Source: *Infrastructure Australia. Market Capacity for electricity generation and transmission projects.*

7.4.3 Securing essential materials

Renewable energy projects will significantly increase the demand for steel and concrete through the mid-2020s. To meet the needs of the 2020 ISP, the *Market Capacity for Electricity Infrastructure* analysis projected both steel and concrete demand to nearly double by 2028, to 0.62 million tonnes and 1.3 million cubic metres respectively[83]. (AEMO is collaborating with Infrastructure Australia to update these projections for the 2022 ISP.) These demands equate to 8% of Australia's annual crude steel production, and 3% of its concrete production. Most of that steel is needed for wind turbine towers, as Australian manufacturers build up capacity to displace imports, though these industry dynamics remain uncertain. Pumped hydro projects account for most of the demand for concrete.

[88] Infrastructure Australia. *Market capacity for electricity infrastructure,* at https://www.infrastructureaustralia.gov.au/market-capacity-electricity-infrastructure.

7.4.4 Project sequencing

Any efforts to smooth out these demand curves for workforce, plant and materials will assist in capping project costs. The ISP has commenced that work by giving participants more certainty on the timing of the large-scale transmission builds, which should assist in negotiating better contract outcomes, and securing long-lead and specialist equipment well in advance and at lower cost. However, project timings in the ISP deliberately allow time for stakeholder engagement and more precise scheduling by relevant parties. From this base, NEM participants and jurisdictions may collaborate to:

- develop more detailed projections of the skills, plant and materials needed over the next 10-20 years to transform the electricity system,
- coordinate the timing of ISP transmission projects and development opportunities to smooth out the construction schedule and avoid peaks and troughs in workforce, plant and materials demand,
- develop programs to meet those workforce requirements, through domestic training programs and targeted skilled migration, and
- expand supply options for plant and materials, including by investing in new onshore manufacturing (included, for example, in the establishment of new green steel manufacturing in *Hydrogen Superpower*).

7.5 Unlocking the potential of DER

Significant investments by both small and large consumers are driving a forecast five-fold increase in the amount of Australia's DER in *Step Change*: see Section 3.1. The ISP analysis confirms that the transmission projects in the ODP are not sensitive to changes in DER uptake or to distribution network constraints on that uptake: see Section 6.5. Nonetheless, significant innovation will be needed in the NEM's market arrangements and distribution networks to optimise the benefits of DER investment.

7.5.1 Market reforms to unlock DER

Significant market reforms have already been achieved since the 2020 ISP to support the technical integration of DER and other modern energy resources. AEMO considers that active management of DER to maintain the reliability and security of the whole system will be an extension of the current evolution of market signals and technological developments influencing DER, although with uncertainty that is incorporated into the modelled scenarios. The emergence of VPPs across the NEM is expected to assist in maintaining grid reliability and provide further benefits for consumers. However, full integration requires a step change in engagement to ensure consumers, retailers, networks and other market participants increase the orchestration of new technologies and resources, to increase benefits to consumers and enable the grid to maintain security and reliability at lower cost.

To that end, the ESB's Post 2025 DER Implementation Plan provides a three-year roadmap towards the effective integration of DER and flexible demand in the NEM. It considers the technical, market, system, consumer protections and governance reforms required to deliver key outcomes for consumers, and sequences reform activities to prioritise urgent and emerging issues and deliver effective consultation with industry stakeholders and consumer advocates. AEMO is progressing a range of these reforms in collaboration with the ESB and other market bodies. For example, the 'Scheduled Lite'[89] initiative will provide a voluntary mechanism for DER and flexible demand to contribute to DER visibility and provide dispatchability services to the power system.

7.5.2 Expanded role of distribution networks to unlock DER

Distribution networks are essential for an efficient, reliable, and secure power system. AEMO is seeking to strengthen the links between the ISP and distribution network planning processes, establishing a working group with Distribution Network Service Providers (DNSPs) and Energy Networks Australia (ENA).

The group recognises the complex dynamics that arise as technologies such as PV, batteries and EVs grow in popularity, with constraints existing behind the meter, and across distribution, sub-transmission and transmission networks. These dynamics need to be well understood and planned for to support the long-term vitality of the wider power system and the electricity market.

The group's observations are:

- Customer and grid-connected DER is now a fundamental component of the electricity system, and emerging export constraints in some areas of the distribution network need to be managed accordingly. Detailed technical and engineering studies are required to estimate the prevalence of constraints and their impacts on customers – particularly at times of high and low demand.
- DNSPs are best-placed to coordinate the assessments of distribution network constraints due to their local knowledge. The AER is currently developing a framework for assessing DER integration expenditure [90].
- Adopting the same set of inputs, assumptions and scenarios can help align distribution, transmission and supply-side investments.
- AEMO will continue to collaborate with DNSPs on the future capability of distribution networks to provide two-way flows and how that evolving capability might impact on DER forecasts.

7.6 Preparing the NEM for 100% renewables

Maximum instantaneous penetration of renewables[91] is a common global metric to compare the capability of power systems to securely operate with renewables. On 15 November 2021, the NEM reached its current instantaneous renewable penetration record of 61.8%, a record that has increased at an average rate of +6.7% per year over the past four years.

By 2025, the availability of renewable generation will exceed customer demand at times. This underscores AEMO's priority to develop power systems that are capable of running at up to 100% instantaneous renewable penetration by 2025 to deliver reliable and affordable energy to consumers. The share of potential resource that is actually dispatched depends on a range of market factors.

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[89] ESB. *Post-2025 Market Design – Final advice to Energy Ministers (Part B), page 88,* at https://esb-post2025-market-design.aemc.gov.au/32572/1629945809-post-2025-market-design-final-advice-to-energy-ministers-part-b.pdf.

[90] AER. *Assessing Distributed Energy Resources Integration Expenditure*, at https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/assessing-distributed-energy-resources-integration-expenditure.

[91] Instantaneous renewable penetration is calculated as the renewable generation share of total large- and small-scale generation. The measure is calculated on a half-hourly basis because this is the granularity of estimated output data for historical distributed PV output. For this calculation, renewable generation includes grid-scale wind and solar, hydro generation, biomass, battery generation and distributed PV, and excludes battery load and hydro pumping. Projected data has been adjusted to account for outages, constraints and time resolution differences.

AEMO's Engineering Framework[92] enables industry participants to collaboratively define the operational, technical and engineering requirements for the NEM's future, and informs the market reforms being undertaken by the ESB. It describes the initial roadmap to inform preparation of the NEM for operation under six identified operational conditions, including contributing to 100% instantaneous renewable energy potential by 2025.

An initial set of initiatives to be progressed has been prioritised with industry. Uplifting System Operator and Network Service Provider capabilities in operational systems, processes, real-time monitoring, and power system modelling will be essential to have the tools to maintain secure operation of the NEM power system as it transitions to significant penetrations of inverter-based resources including DER. AEMO has developed a strategic roadmap for this uplift[93].

* * *

Through the next decade, the NEM must deliver a once-in-a-century transformation in the way electricity is generated and consumed in Australia. That transformation is essential for the Australian economy to enjoy affordable and reliable energy in the future, as well as achieve net zero emissions by 2050.

The 2022 ISP is prepared to help the NEM meet that challenge, and is published at a time when the price and future of Australia's energy are matters of even greater than usual national urgency. A product of deep collaboration over two years, it sets out a roadmap for the NEM that continues to prove itself against market realities. If, for example, recent wholesale electricity prices have been forced higher by higher international fuel prices, domestic coal-plant outages and a lack of transmission capacity, in that order, then investment in low-cost renewable energy and essential transmission is the best strategy to protect against higher prices.

If successful on its mission, the NEM will also support further economic opportunities that are being pursued across its jurisdictions, in new forms of energy exports, low-emission industrial production, and energy-intensive digital industries.

AEMO presents the 2022 ISP as a major and positive contribution towards the sustainable future of Australia's energy, economic, social and environmental systems. AEMO sincerely thanks all those who have contributed, and looks forward to engaging with all NEM participants towards the next ISP.

92 See https://aemo.com.au/initiatives/major-programs/engineering-framework.

93 See https://aemo.com.au/initiatives/major-programs/operations-technology-roadmap.

Supporting documents

ISP Appendices and web assets are available on AEMO's website at:

https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp.

ISP Appendices

- Appendix 1 Stakeholder engagement — see Section 2
- Appendix 2 ISP development opportunities — see Section 3 and Section 4
- Appendix 3 Renewable energy zones — see Section 3.3
- Appendix 4 System operability — see Section 4
- Appendix 5 Network investments — see Section 5
- Appendix 6 Cost benefit analysis — see Section 6
- Appendix 7 Power system security — see Section 4.3

ISP web assets

- Chart data
- Generation outlook

IASR

Information relating to inputs, assumptions and scenarios is available at: https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

- *2021 Inputs, Assumptions and Scenarios Report* (IASR).
- IASR Addendum
- Updated IASR Workbook

Non-network consultations

Following a consultation process, AEMO has assessed non-network options for two actionable projects:

- New England REZ Transmission Link[94], and
- Reinforcing Sydney, Newcastle and Wollongong Supply[95].

These projects will progress under the *Electricity Infrastructure Investment Act 2020* (NSW) rather than the ISP framework – see Section 5.4.

[94] See https://aemo.com.au/consultations/current-and-closed-consultations/2022-isp-consultation-non-network-options-new-england-rez-link.

[95] See https://aemo.com.au/consultations/current-and-closed-consultations/2022-isp-consultation-non-network-options-supply-sydney-newcastle-wollongong.

List of tables and figures

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