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

Contents

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.

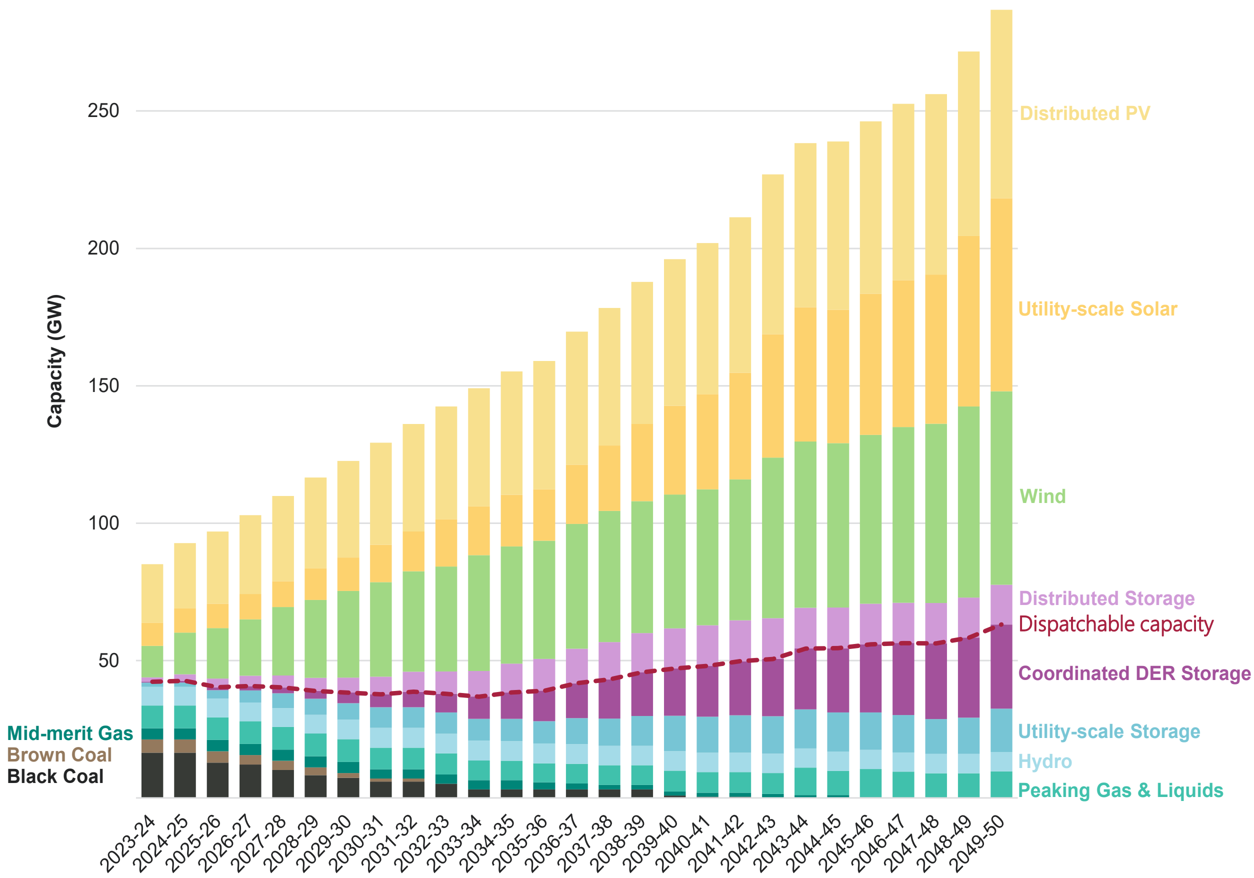
When successful, the transformation of the NEM will deliver low-cost renewable electricity with reliability and security, help meet regional and national climate targets, and contribute significantly to regional jobs and economic growth.

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.

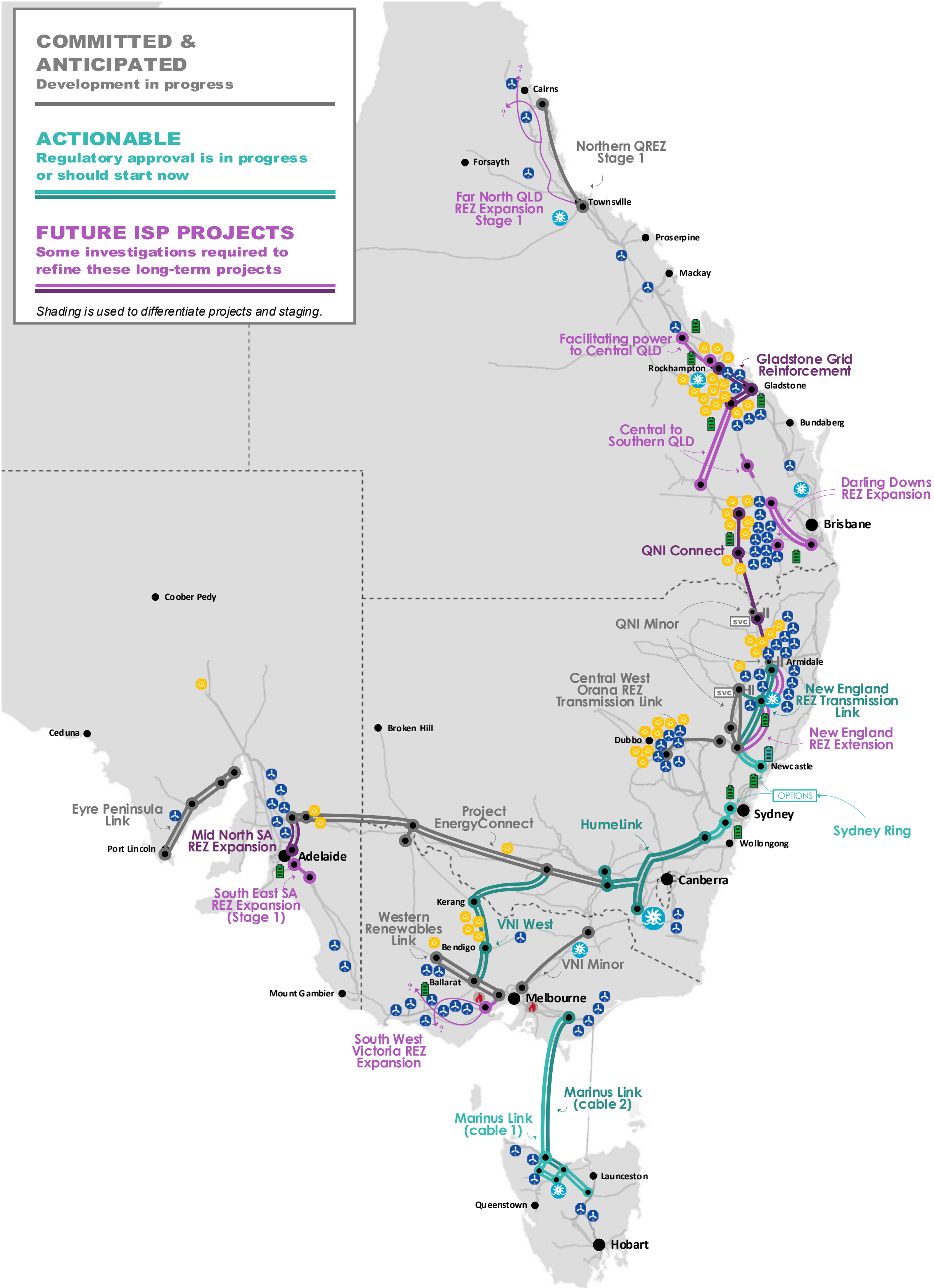
[3] See https://aemo.com.au/initiatives/major-programs/operations-technology-roadmap.

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.

[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.

* * *

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.

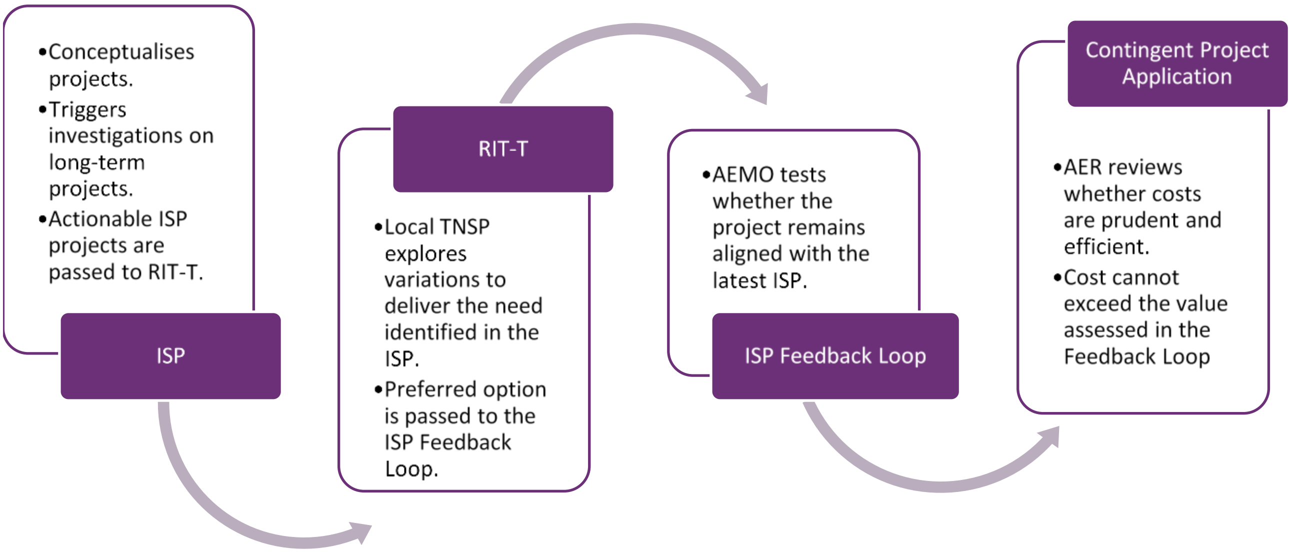
[11] NER 5.22.2

[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

<table>
<tr><th>Need</th><th colspan="2">Operational requirements considered when developing the ISP</th></tr>
<tr><td rowspan="3">Reliability</td><td rowspan="3">Resource adequacy and capability
• There is a sufficient overall portfolio of energy resources to continuously achieve the real-time balancing of supply and demand.</td><td>Energy resources provide sufficient supply to match demand from consumers at least 99.998% of the time.</td></tr>
<tr><td>Operating reserves exist to provide the capability to respond to large continuing changes in energy requirements.</td></tr>
<tr><td>Network capability is sufficient to transport energy to consumers.</td></tr>
<tr><td rowspan="2">Security</td><td>Frequency management and inertia response
• Ability to maintain system frequency within operating standards.</td><td>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.</td></tr>
<tr><td>Voltage management and system strength
• Ability to maintain voltages on the network within acceptable limits.
• System strength is above minimum levels.</td><td>Voltage remains within operating standards, fault levels are below equipment ratings, and system strength/fault levels are maintained above minimum requirements.</td></tr>
</table>

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.

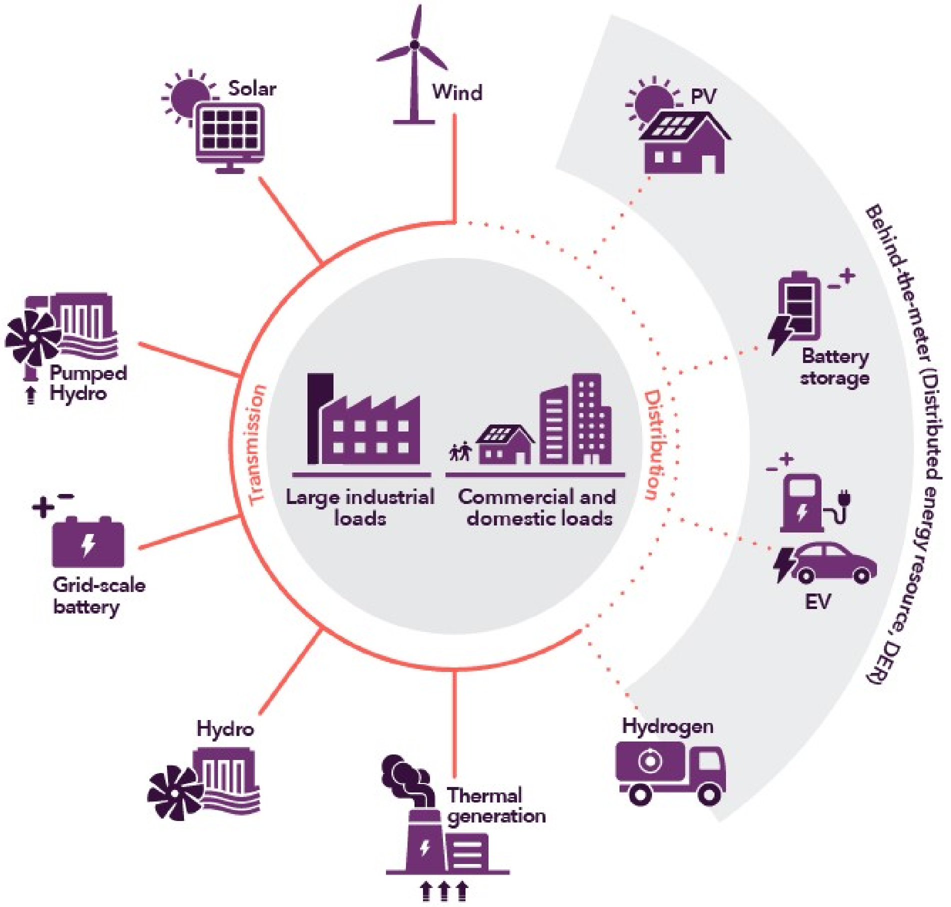
The first major complexity is the interaction between DER and utility-scale supply (see Figure 4). As more behind-the-meter PV is installed, and more batteries and EVs charge and discharge, the demand profiles for grid-supplied energy shift. This in turn influences how generators operate, and increases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

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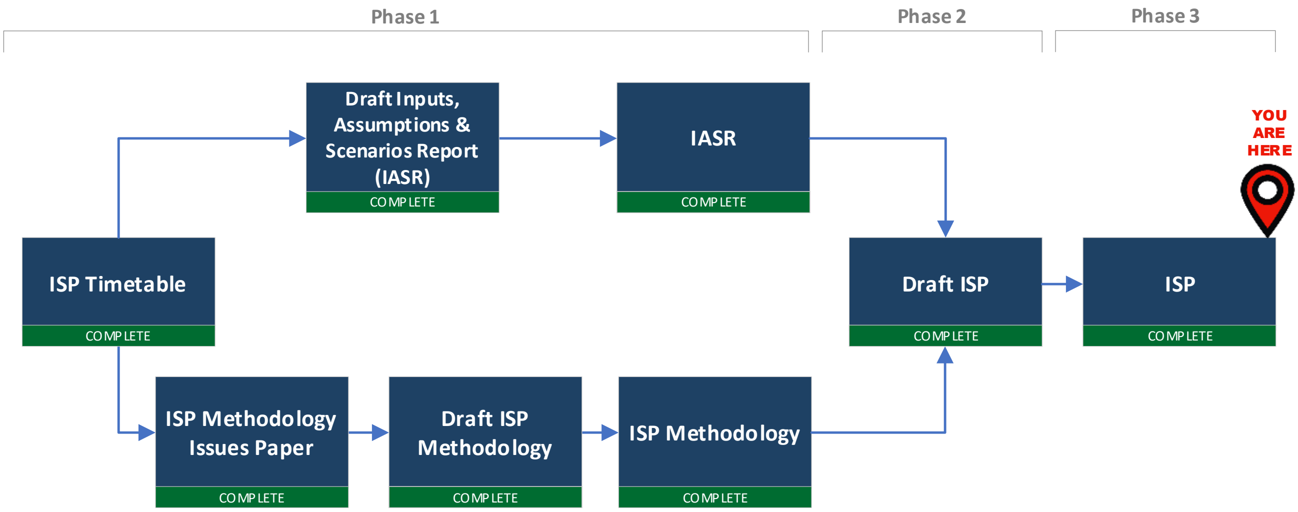
[23] See https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-inputs-assumptions-and-scenarios-report.pdf?la=en.
[24] See https://www.aemo.com.au/-/media/files/major-publications/isp/2021/2021-isp-methodology.pdf?la=en
[25] See https://www.aer.gov.au/networks-pipelines/performance-reporting/transparency-review-of-aemo-draft-2022-integrated-system-p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

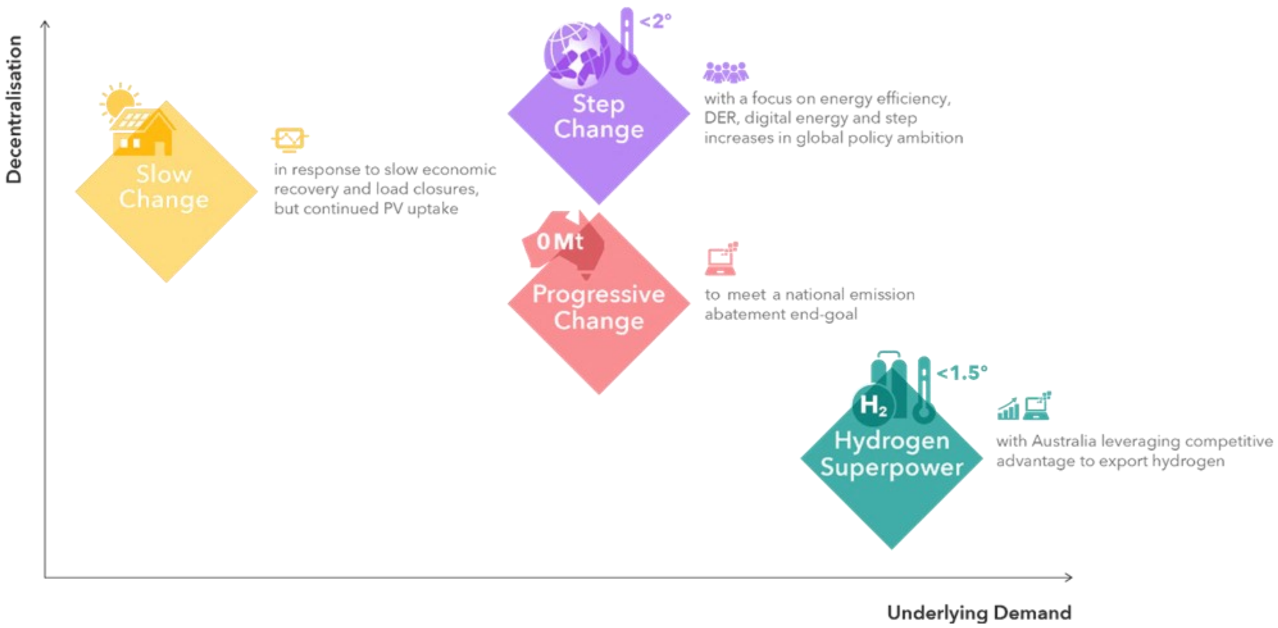
incorporating any changes to policies and programs that may occur. Such policies would be reviewed for the scheduled 2023 IASR, and feed into the 2024 ISP, or any earlier ISP update.

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.

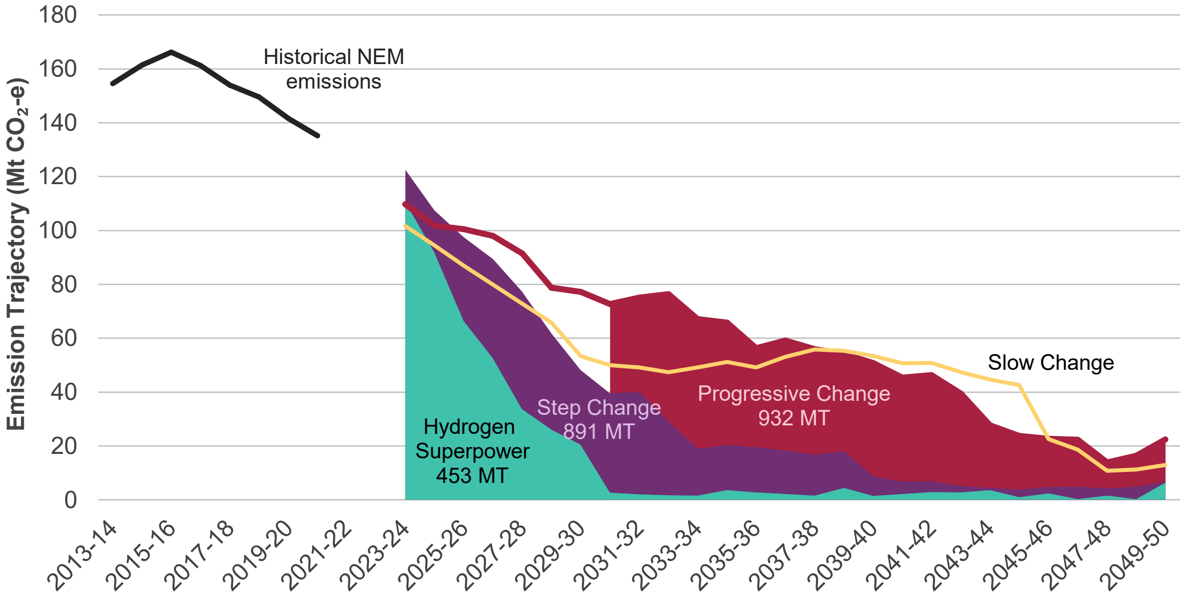
Figure 7 Scenario input assumptions

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.

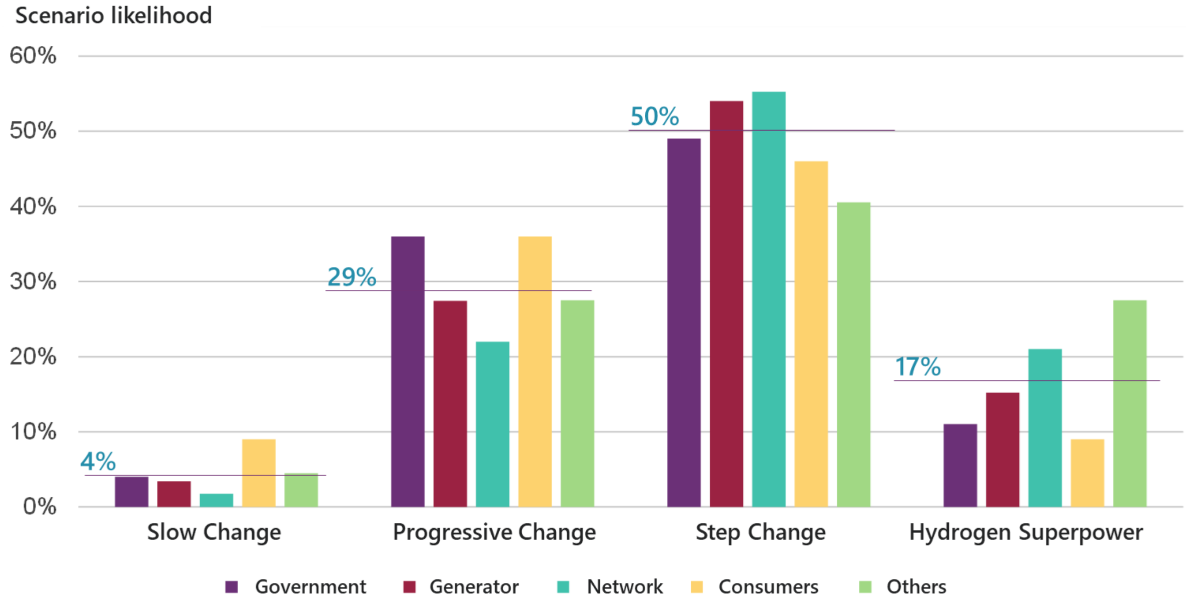
- **First panel considers two scenarios equally likely.** The panel of experts representing government, market bodies, generators, consumer and network service providers first met on 5 October 2021, prior to Australia's net zero emissions commitments at COP26[28]. They deliberated using a Delphi Technique 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.

[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:

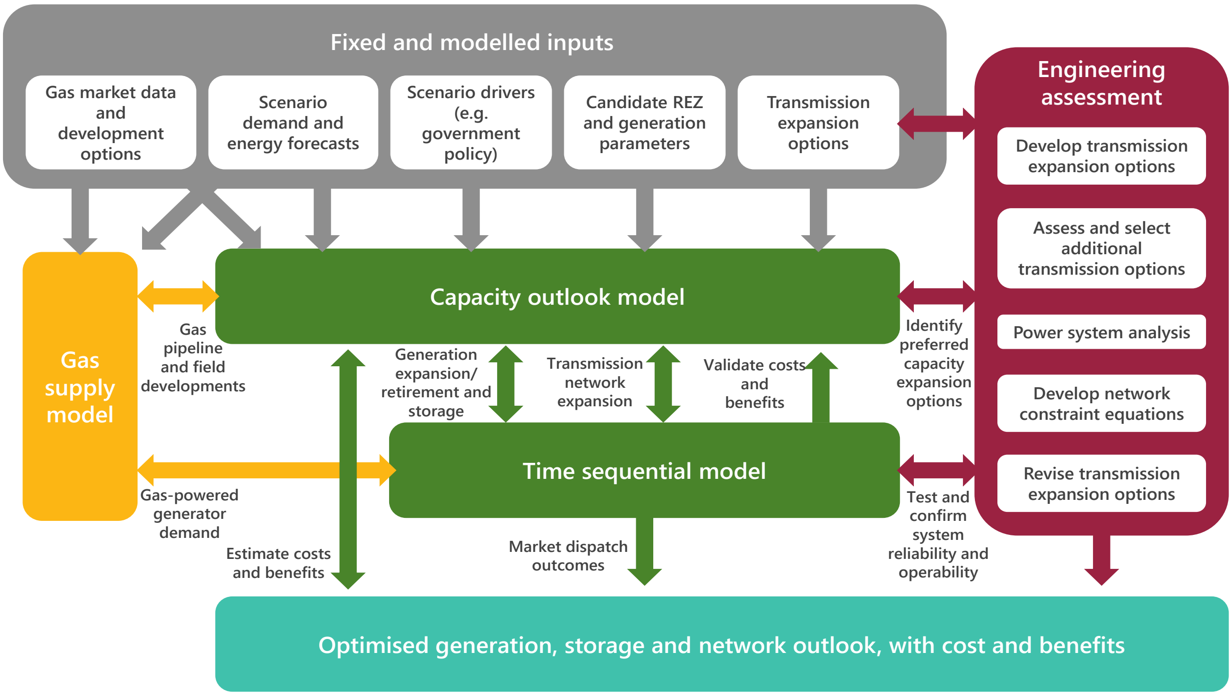
- The **capacity outlook model** projects the generation and transmission build and their dispatch outcomes in each scenario, seeking to optimise capital and operational costs.
- The **time-sequential model** then optimises electricity dispatch for every hourly or half-hourly interval.
- The **engineering 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.*

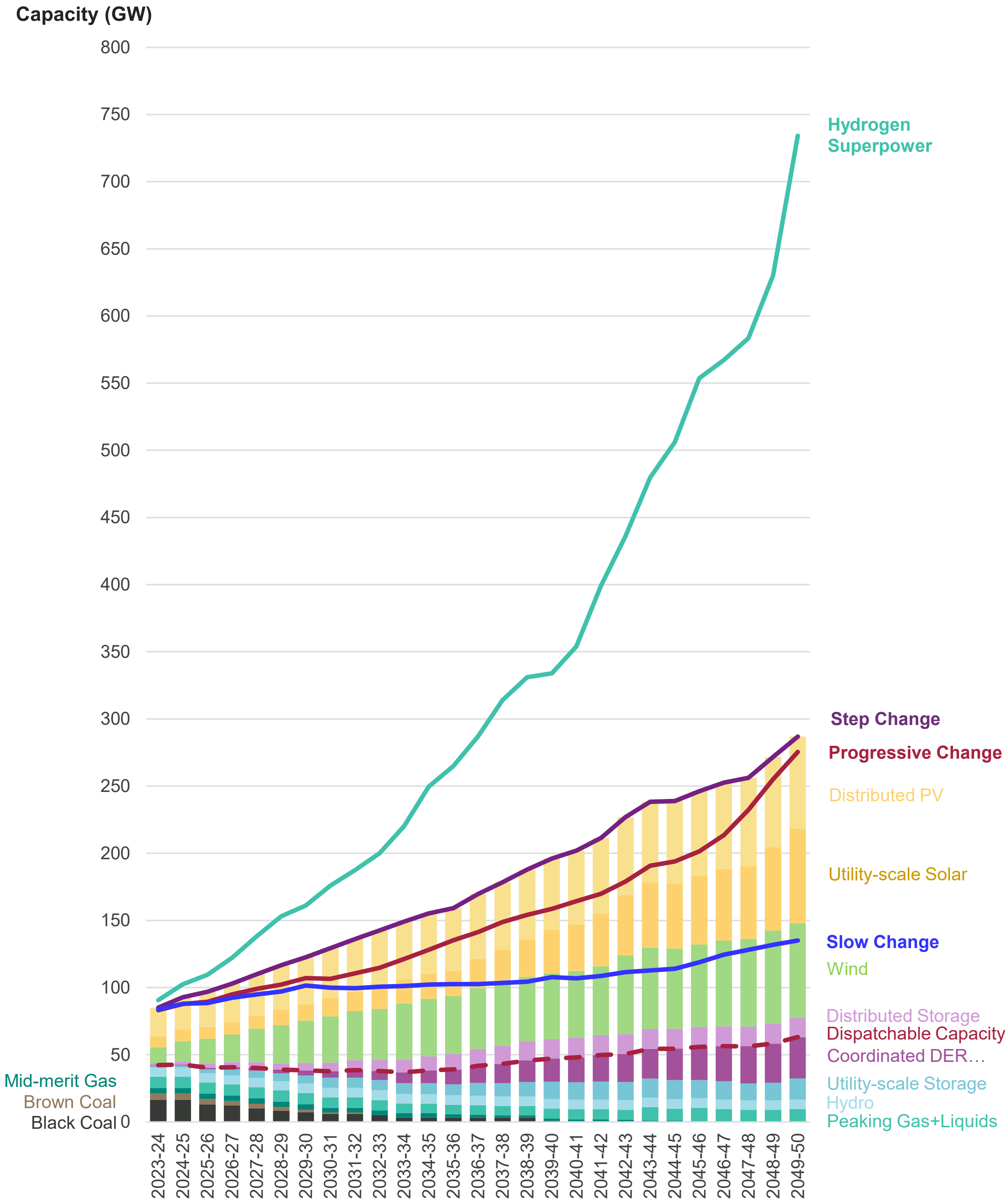
This Part B details how the NEM is forecast to deliver those needs.

- **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

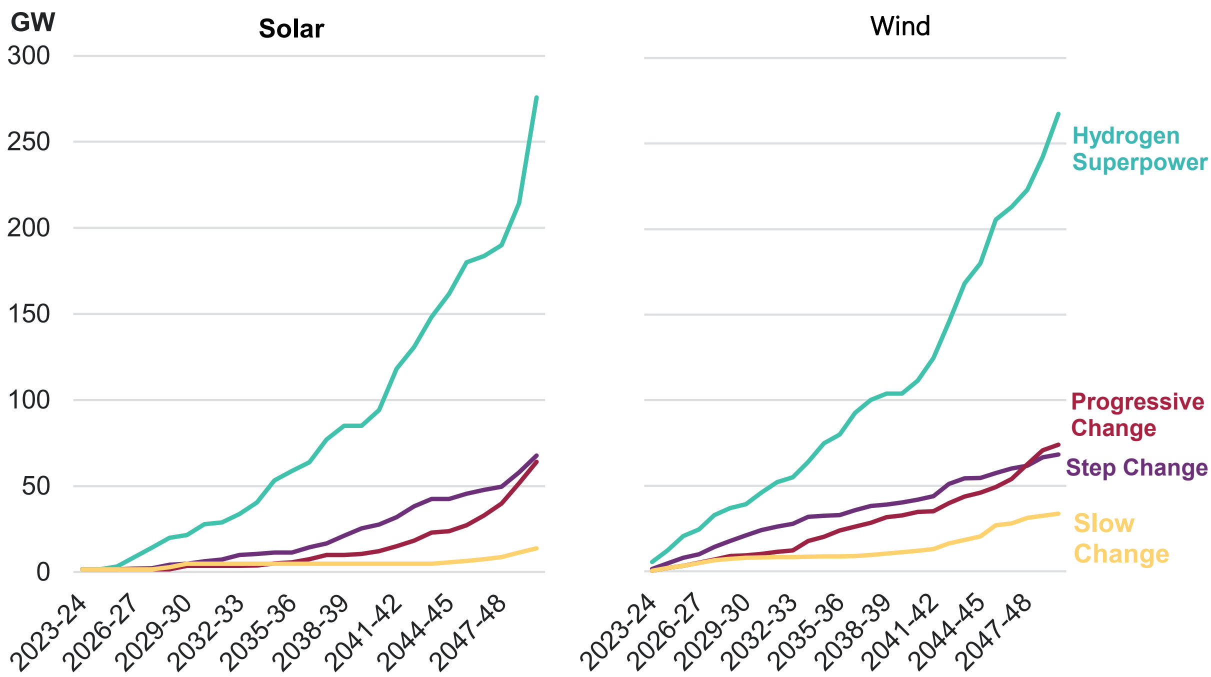
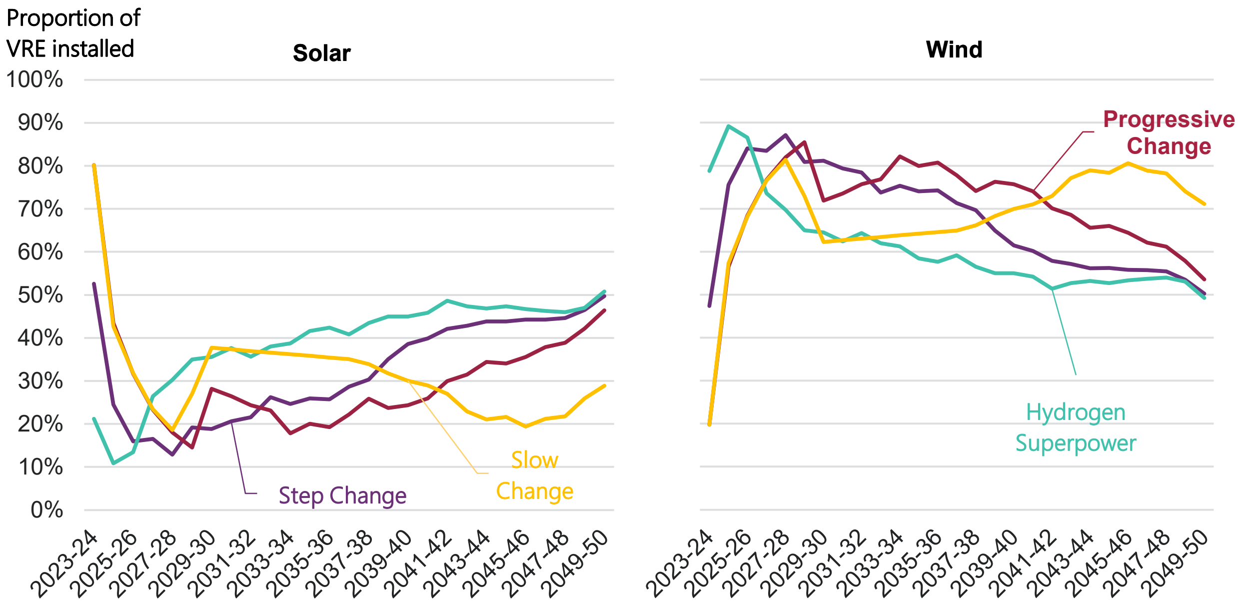


Figure 13 Proportional cumulative development of new utility-scale renewable capacity



3.2.2 The value of geographic diversity and strong interconnection

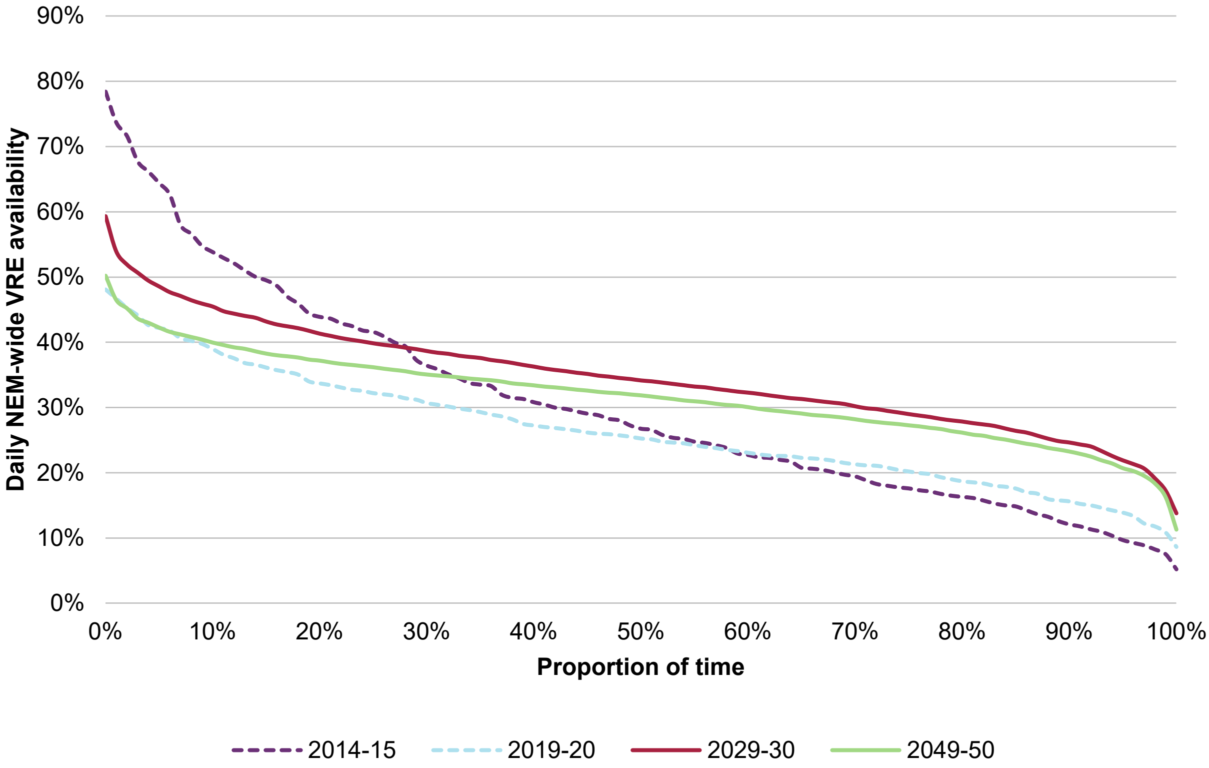
Developing VRE in diverse locations improves the operability of the grid under all weather conditions, bringing multiple benefits. Assuming it can be connected efficiently across the NEM, diversity reduces the variability of renewable generation, the frequency of low aggregate output, and the vulnerability 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.

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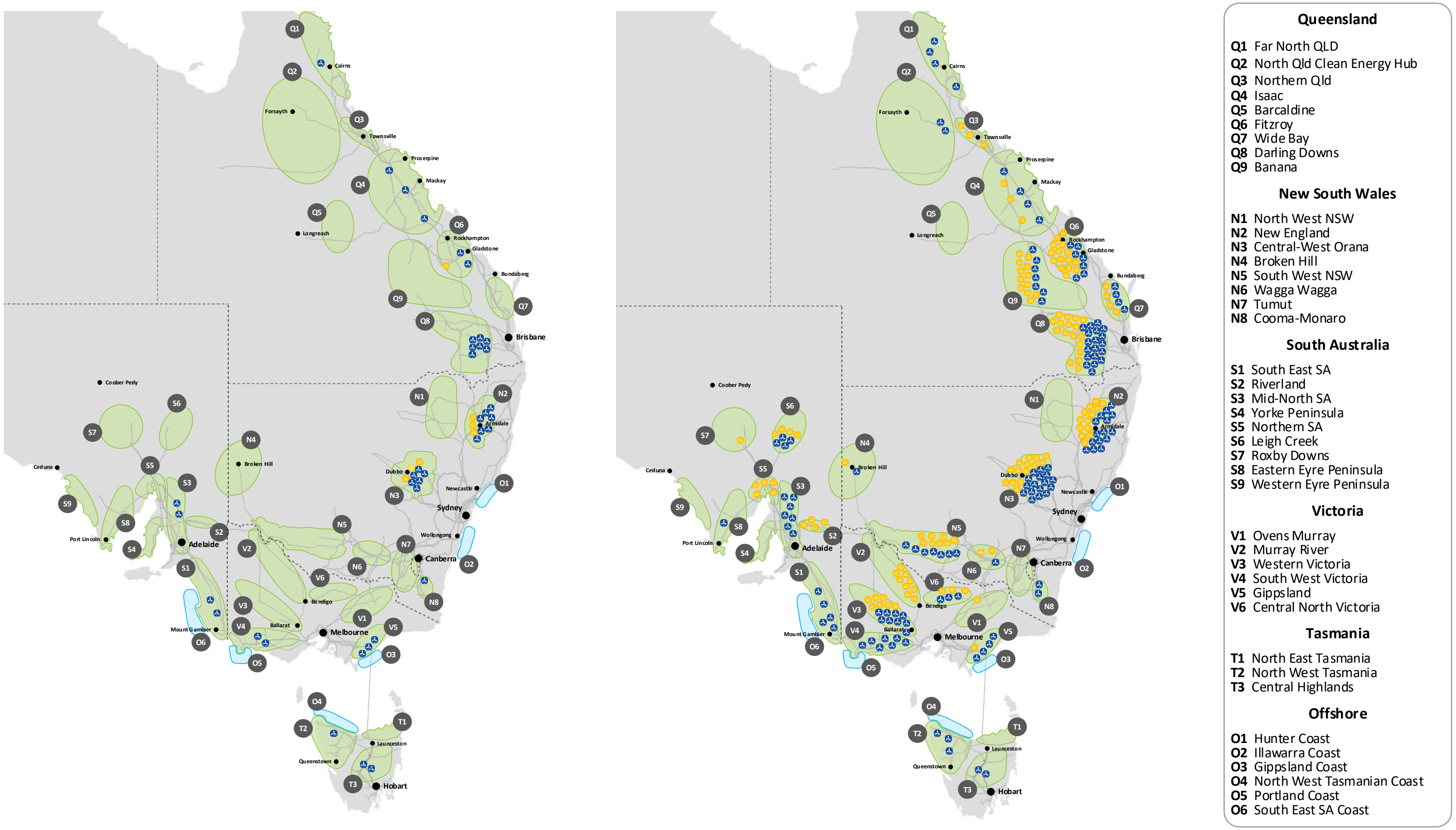
[35] See the NSW Electricity Infrastructure Roadmap, at https://www.energy.nsw.gov.au/government-and-regulation/electricity-infrastructure-roadmap/about-roadmap#-renewable-energy-zones-.

[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.

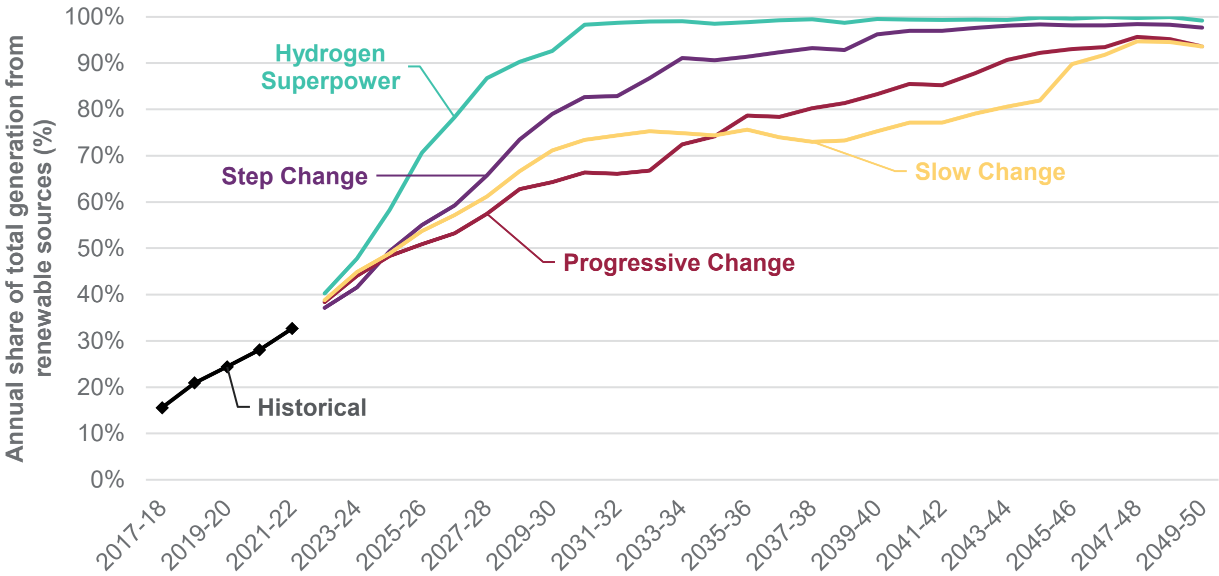
3.4 Rising renewable shares of annual and instantaneous dispatch

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.

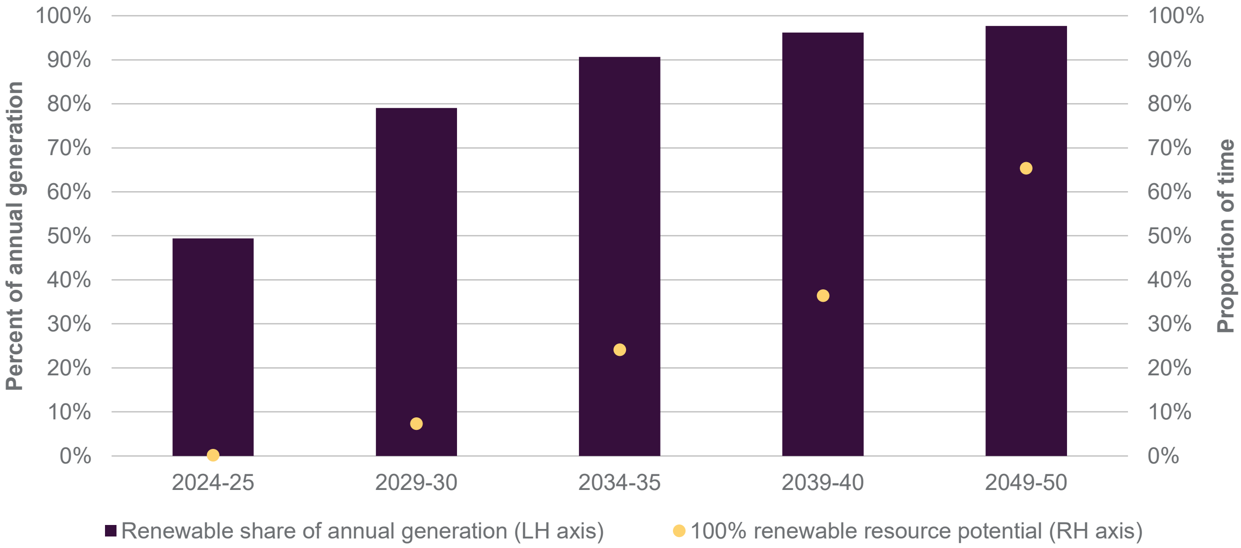
Figure 16 Annual share of total generation from renewable sources (each scenario, optimal development path)



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.

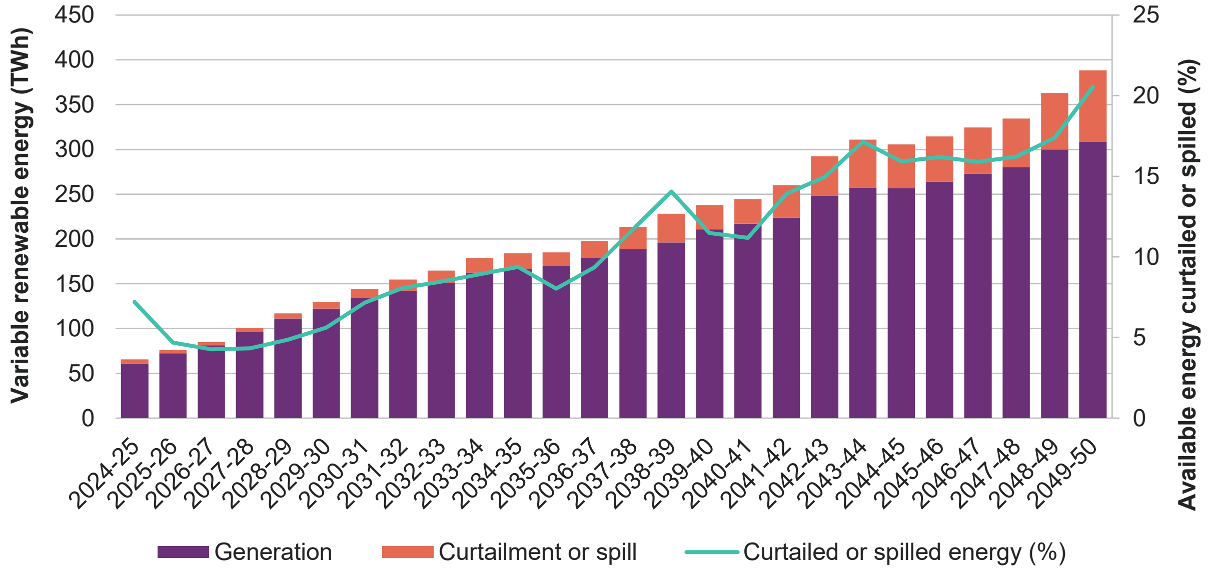
By 2050, the efficient level of curtailed or spilled generation in *Step Change* increases to approximately 20% of total available VRE output: see Figure 18. Market reforms are being developed by the Energy Security

[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

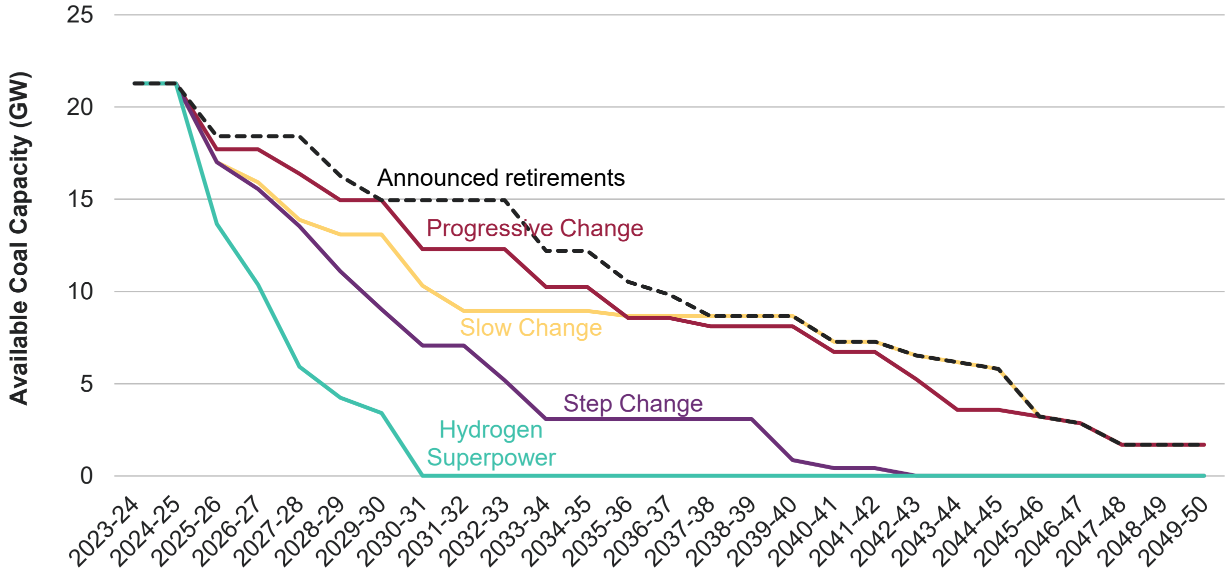
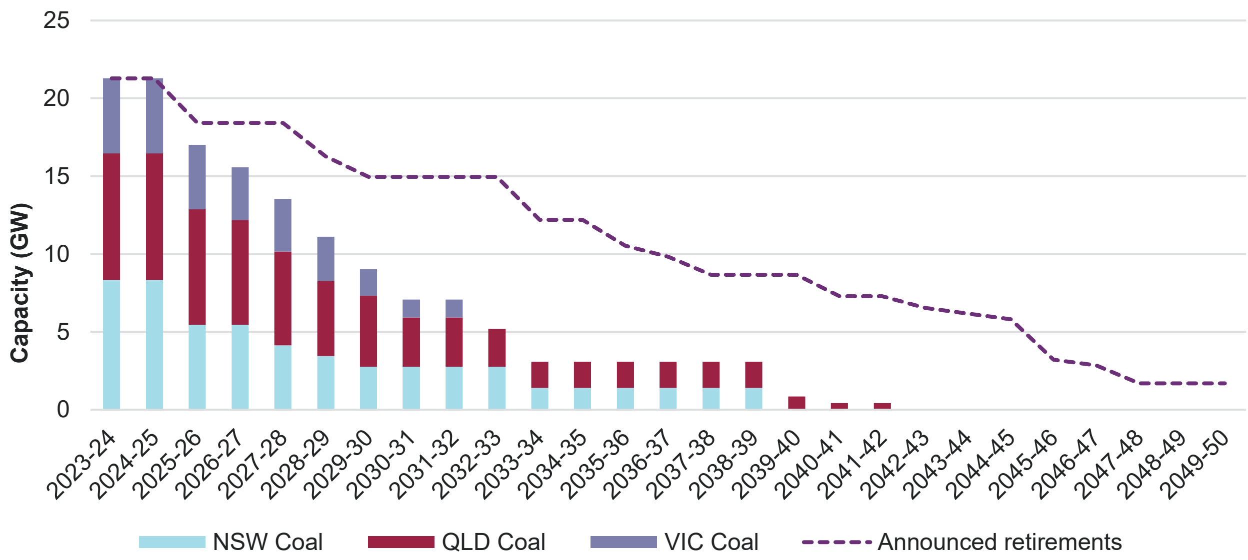


Figure 20 Forecast coal retirements, *Step Change* technology and regional outlook



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:

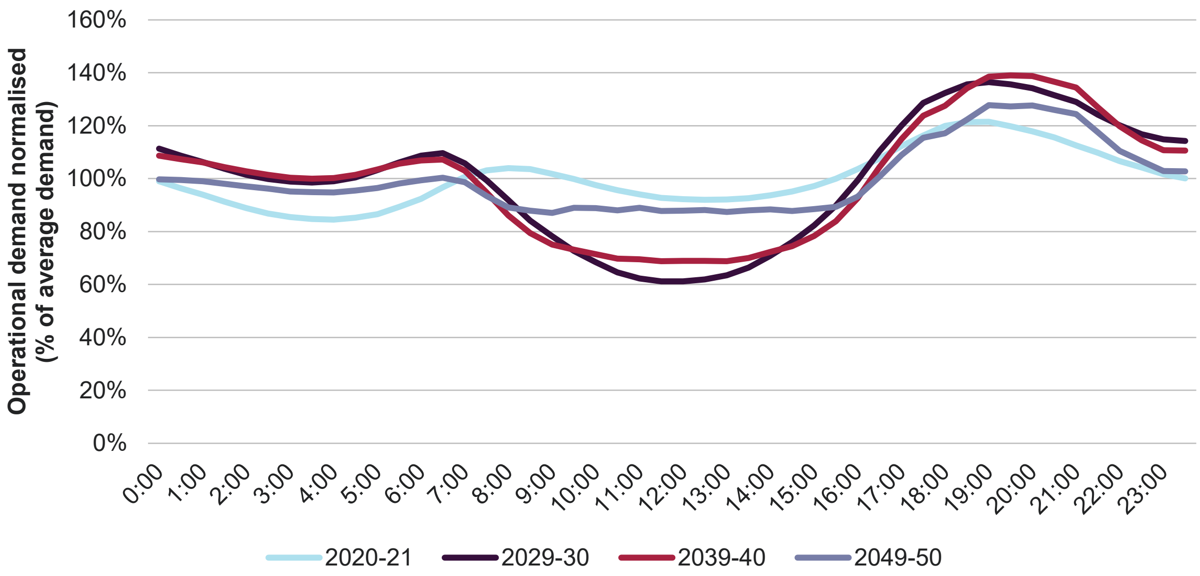
- the NEM's daily operational demand pattern is forecast to change as distributed storage helps soak up excess distributed PV during the day, and reduce peak demands in the evening,
- different storage depths are needed to manage this intra-day pattern, as well as match supply and demand between days 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.

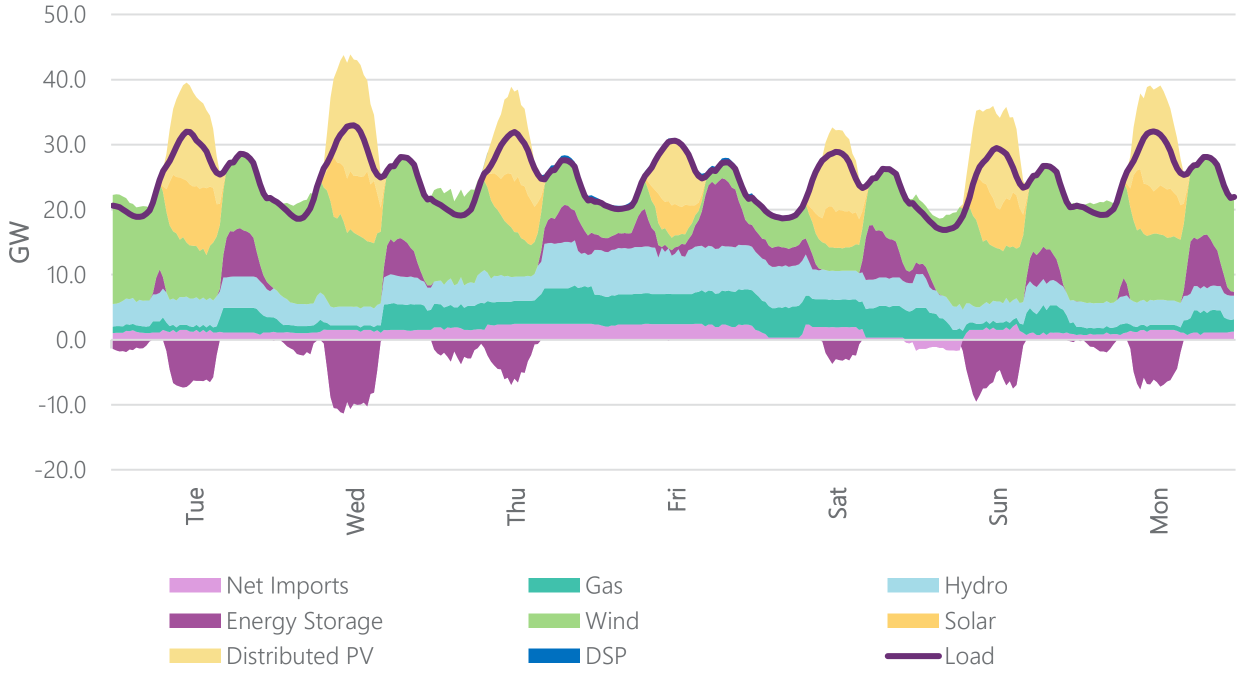
Figure 22 shows how the different generation sources interact to deliver electricity to consumers across New South Wales, Victoria, South Australia and Tasmania through a forecast winter week in July 2040, using a historically observed set of weather conditions. In this sample winter week, weather conditions 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.

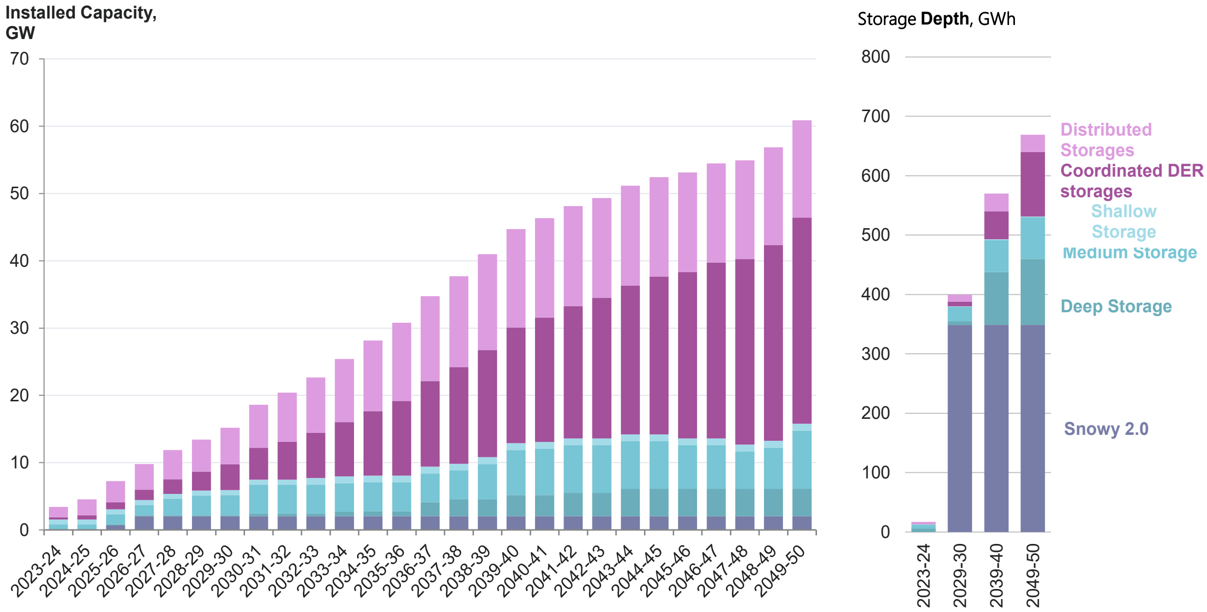
Different types and depths of storage

- **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.

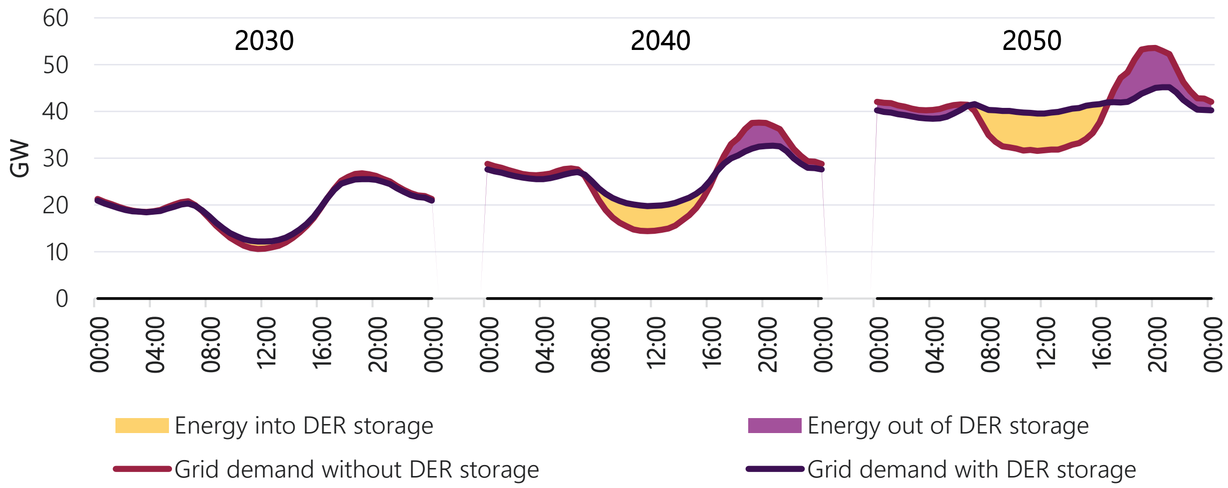
The need for medium-depth storage includes 2 GW of storage that can be dispatched for at least eight hours, needed by the end of 2029 to help meet the objectives of the New South Wales Roadmap. The 2021 IIO Report[42] recognises the supply chain and other issues that may delay delivery of these projects, 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.

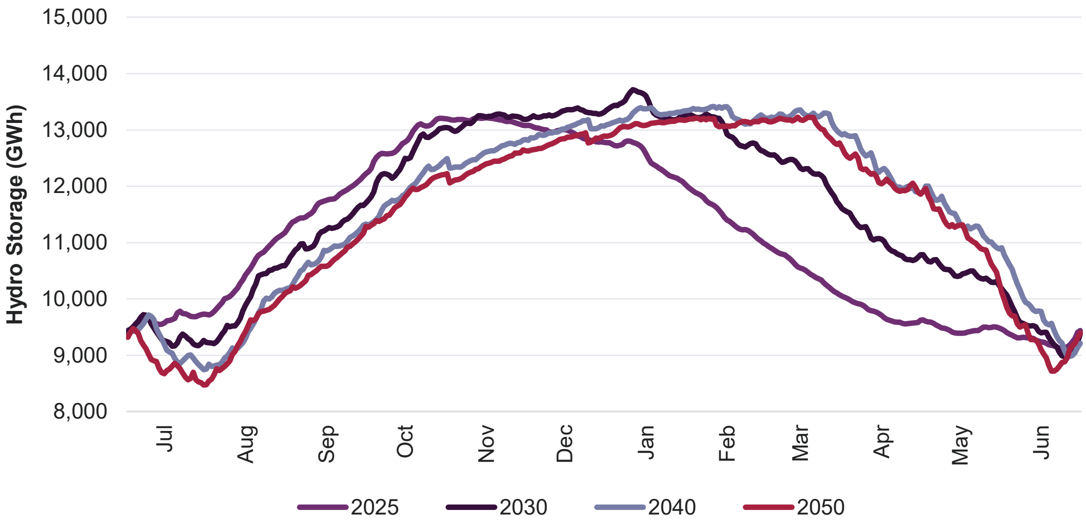
technologies, with support of retailers, networks and other market participants to overcome any adoption challenges: see Section 7.5.

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.

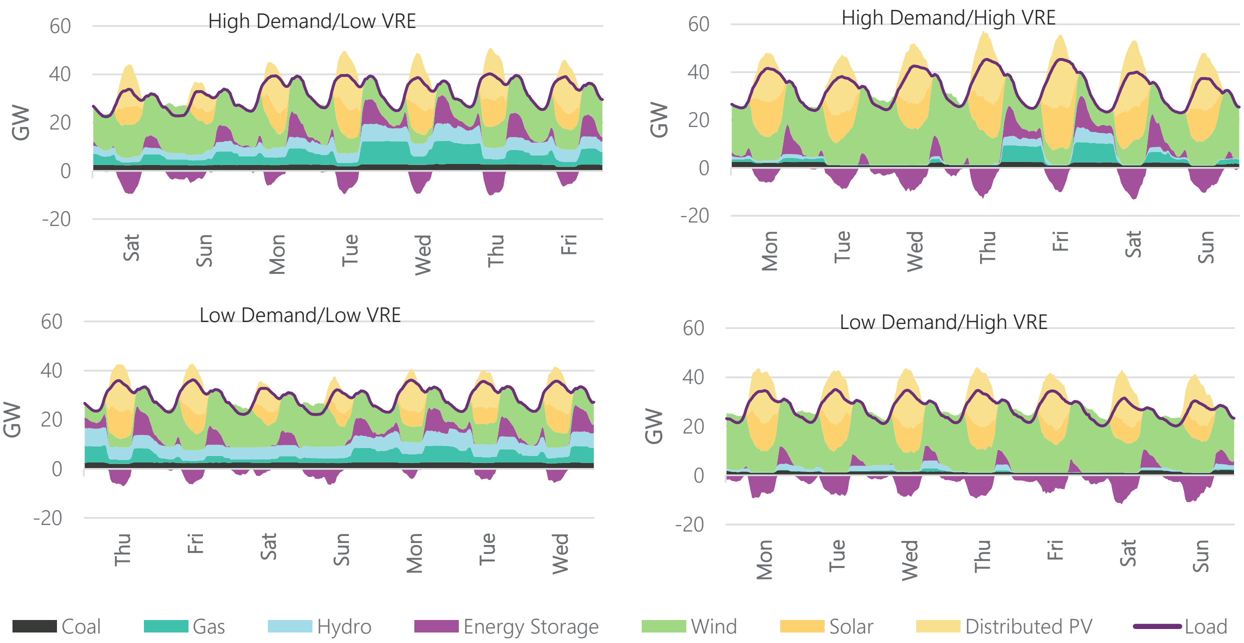
and/or within the distribution system. This total storage capacity is equivalent to 30 times the existing Wivenhoe Power Station, and over 20 times the scale of stored energy at Wivenhoe.

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.

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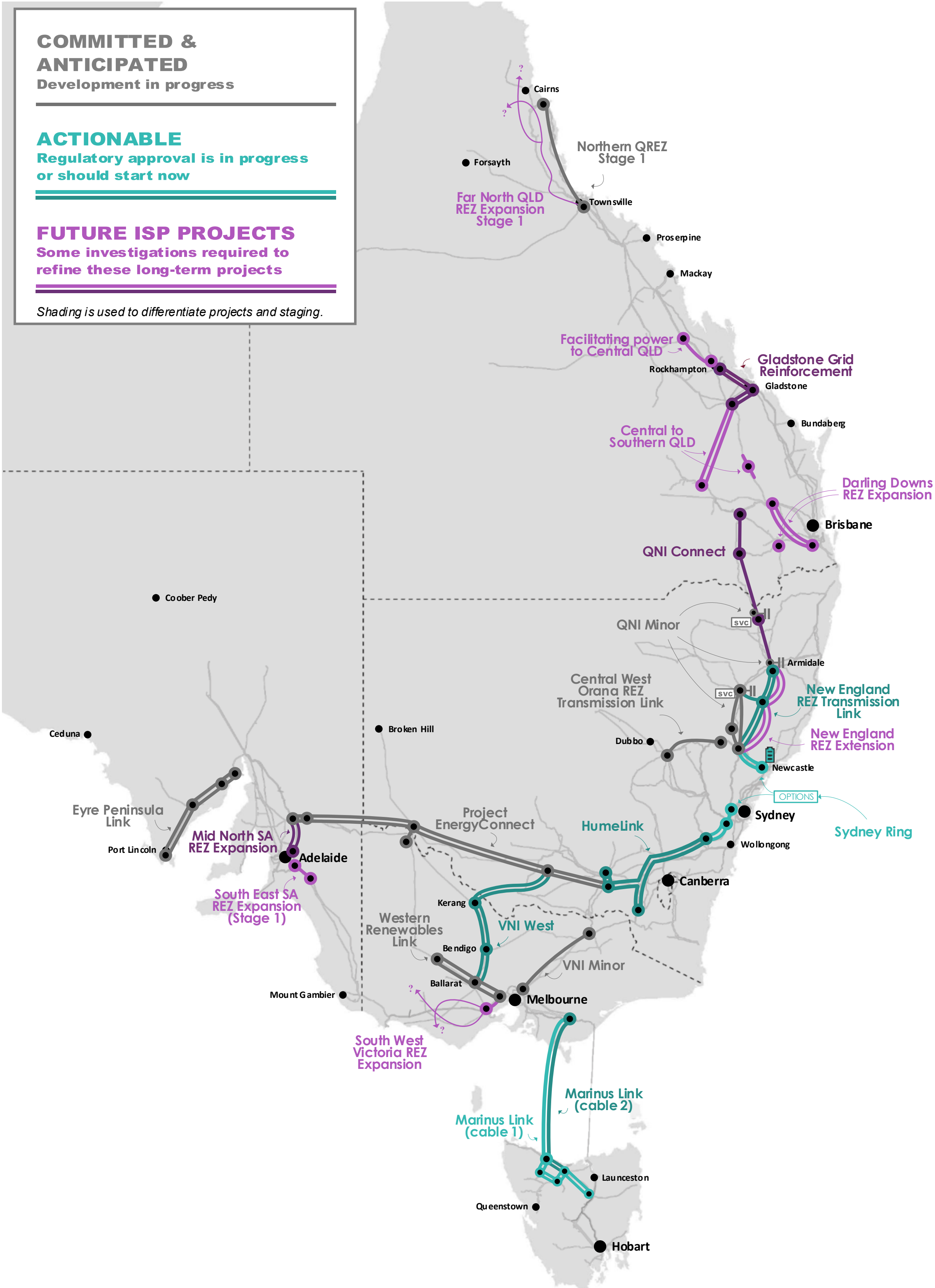
[49] Minor updates to inputs and assumptions are outlined in the 2021 Inputs and Assumptions workbook, available at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

[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.

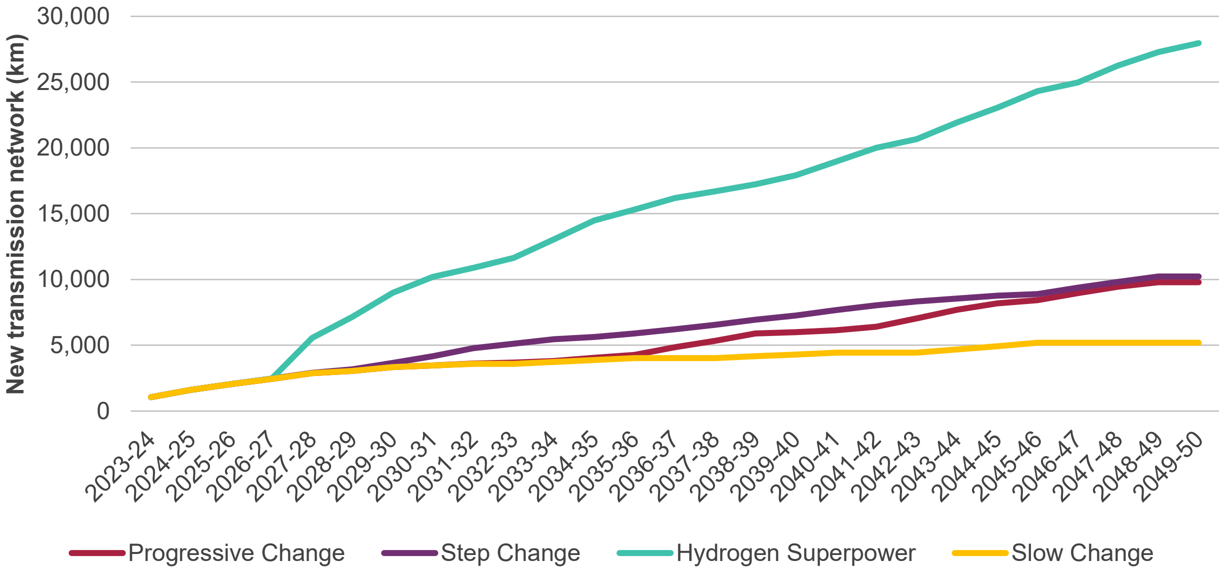
Figure 27 Map of the network investments in the optimal development path



† 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.

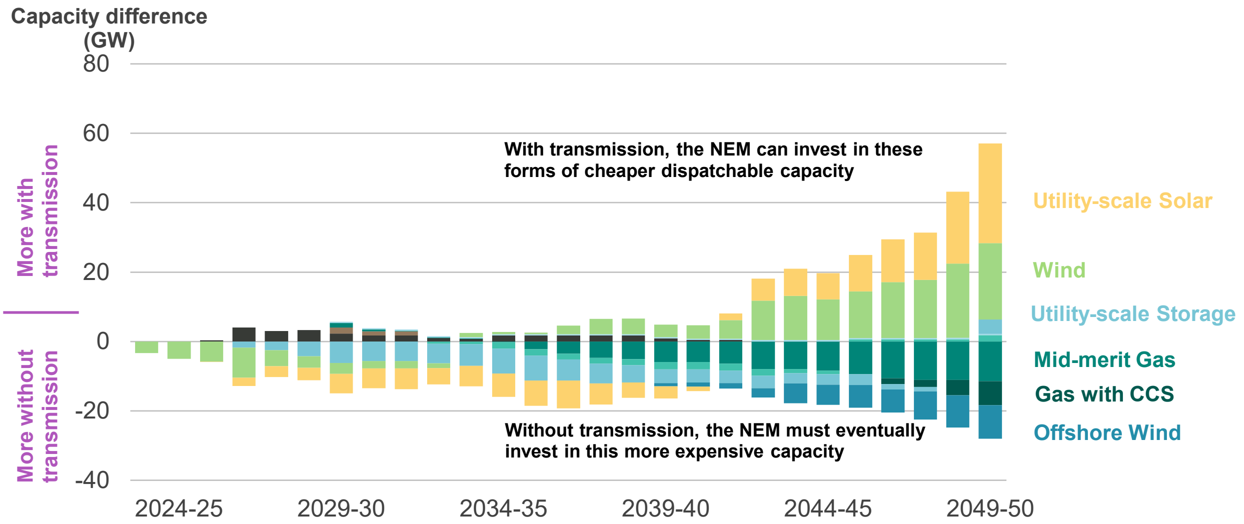
[55] This does not reflect the full capital investment in network in today's dollars, but rather the NPV of the equivalent annuity calculated from time of commissioning to 2050-51.

[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:

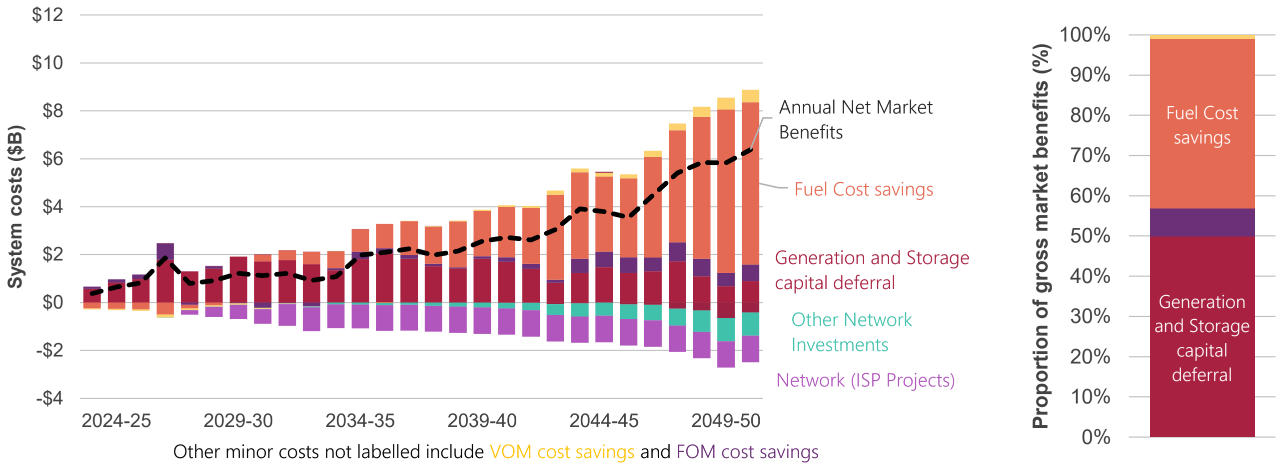
- **in the next 15 years**, by balancing use of existing generation against even-more-rapid development of VRE and storage to achieve the decarbonisation outcomes over the ISP horizon.
- **in the longer term**, by avoiding the need to rely on greater volumes of gas-fired generation and generation technologies 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.

[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.

[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.

[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).

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[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.

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[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.

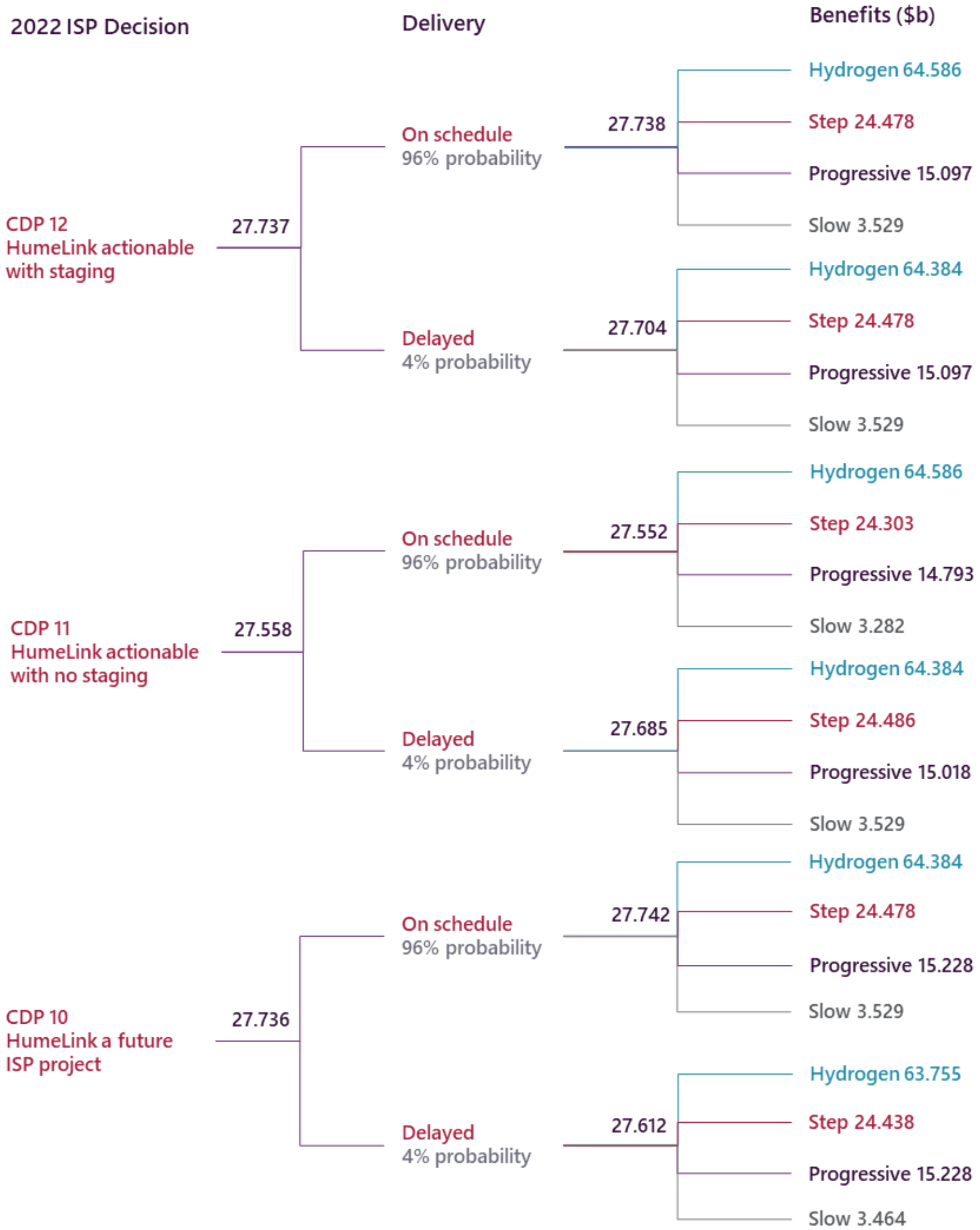
[76] To simplify the calculation, it is assumed that a decision made now cannot predict the scenario that is playing out, whereas in two years' time it can. In reality, there will still be uncertainty.

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.

[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.

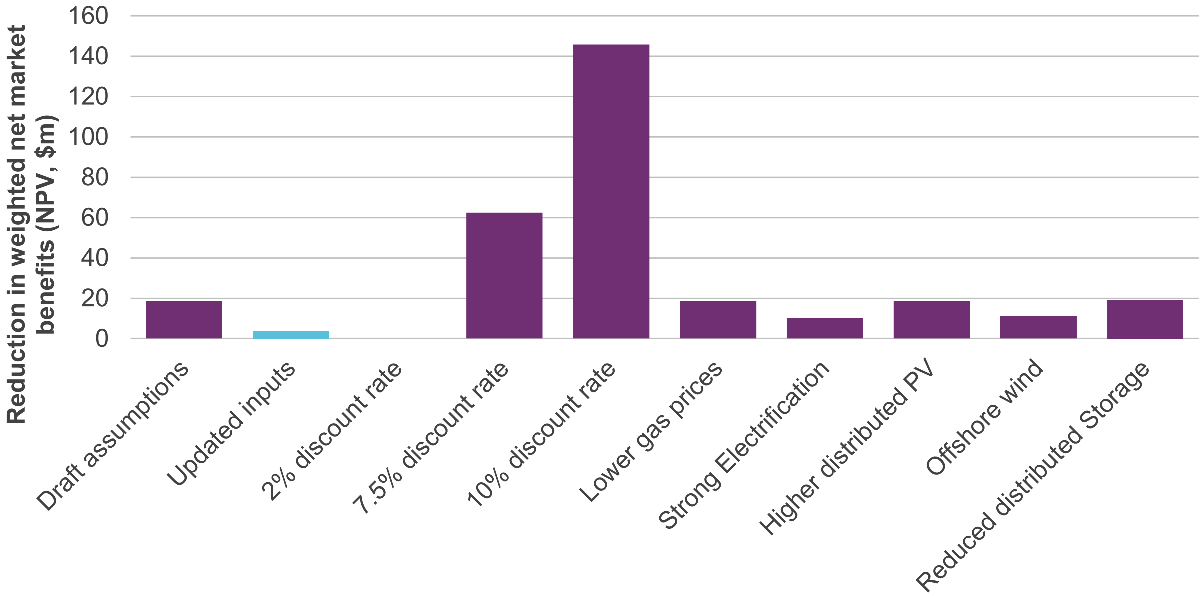
Figure 32[80] shows the impact of varying these assumptions on the scenario-weighted net market benefits of the ODP, compared to the top-weighted CDP within each assessment.

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

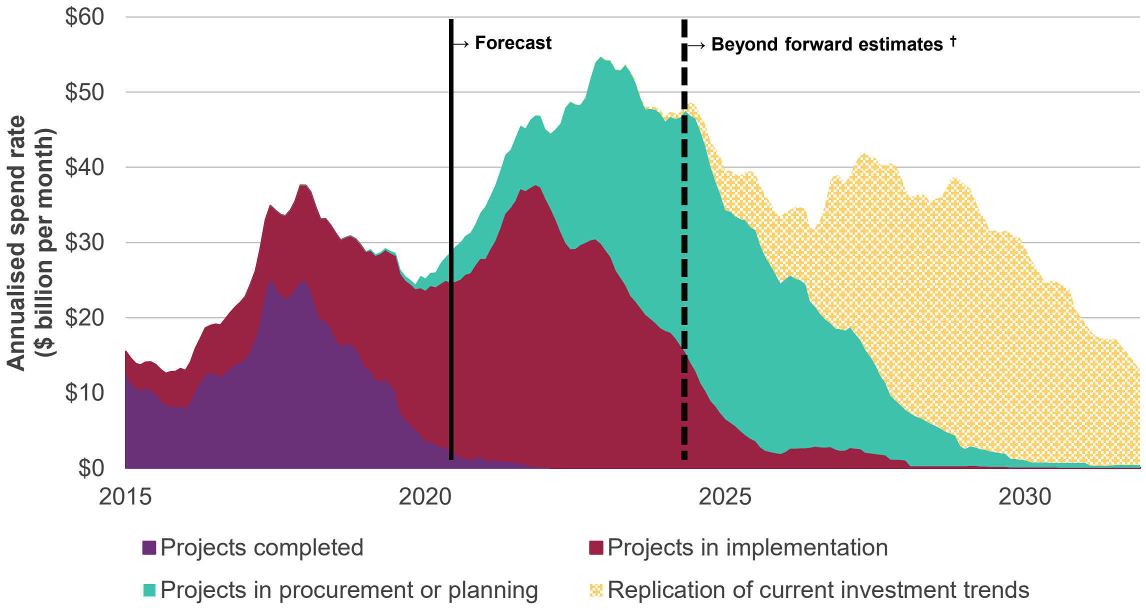
NEM's supply chain needs. This section reviews insights from that and similar work that may assist NEM participants in their future project planning, and suggests that:

- **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



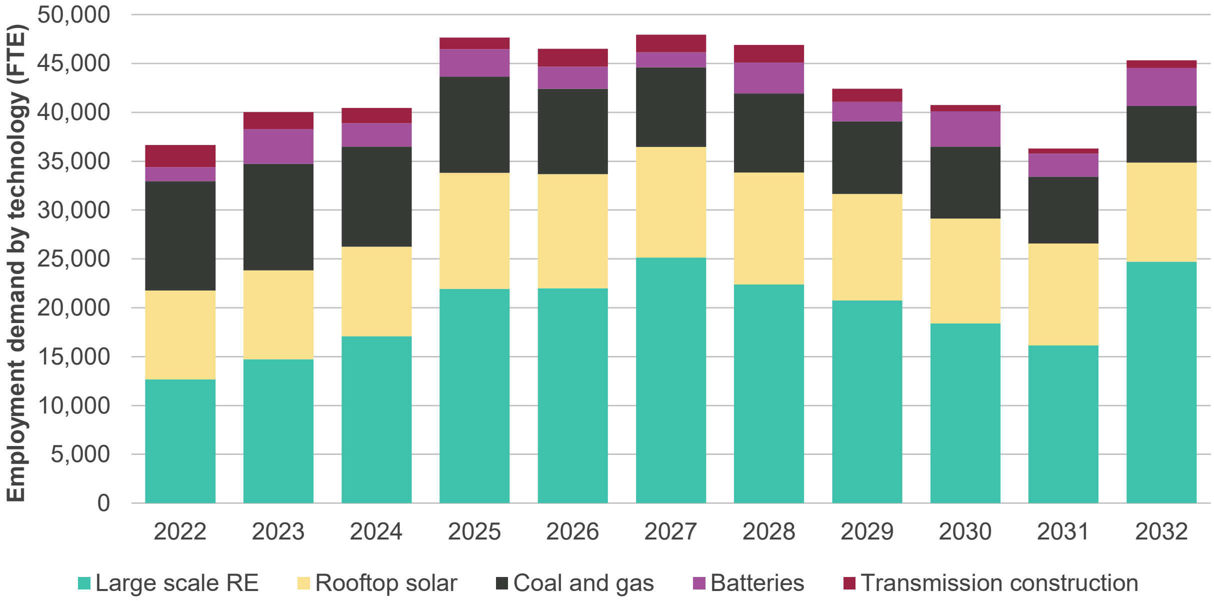
Source: *Infrastructure Australia. Infrastructure Market Capacity (October 2021).*
† Available data for the period beyond forward estimates is limited. Actual spend beyond 2025 will be dependent on future project announcements. The replication of current investment trends demonstrates the spend profile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

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[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

Tables

Figures

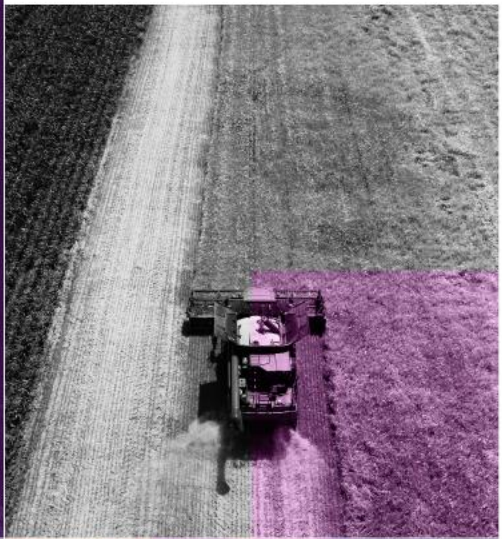
AEMO

AUSTRALIAN ENERGY MARKET OPERATOR

Draft 2024 **Integrated System Plan**

For the National Electricity Market

A roadmap for the energy transition



Important notice

Purpose

AEMO publishes the Draft 2024 *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 is generally based on information available to AEMO as at 30 October 2023 unless otherwise indicated.

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Version control

Version	Release date	Changes
1.0	15/12/2023	Initial release.
1.1	15/01/2024	Updates to Figures 5, 6 and 7 (amend apportionment of losses), Figures 9 (add in mid-merit gas) and Figure 19 (correct Snowy 2.0 depth). Corrections to text associated with Figures 5,6, 7 and 19 to reflect figure edits. Minor typographical corrections including reference to the initial year for Victorian offshore wind targets.

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.

CEO preface

I am pleased to present AEMO's Draft 2024 Integrated System Plan (ISP) for your review and comment.

The plan is a roadmap for the energy transition in the National Electricity Market (NEM) over at least the next 20 years, in line with government policies to reach a net zero economy by 2050.

The plan outlines the lowest-cost pathway of essential generation, storage and transmission infrastructure to meet consumers' energy needs for secure, reliable and affordable energy, and to achieve net zero emissions targets.

AEMO's message is clear and consistent: urgent action is needed to deliver benefits for consumers as the NEM moves away from its traditional dependency on coal-fired generation. Release of this draft comes at a time of ongoing and significant change in the way Australia's electricity supply is generated, transferred and consumed.

Australia's ageing coal-fired power stations are closing down. Renewable energy connected by transmission, firmed with storage and backed up by gas is the lowest cost way to supply electricity to homes and businesses through Australia's energy transition.

Together, as a nation, we are facing important decisions that shape the way our power system will operate in the coming decades. Twenty five years ago Australia took a bold step forward in creating the National Electricity Market to maximise benefits to consumers from existing infrastructure. Today, Australian consumers urgently need new infrastructure to ensure reliable and affordable electricity supply going forward.

AEMO prepares the ISP every two years in collaboration with its stakeholders, including energy companies, consumer organisations, and agricultural and First Nations communities. AEMO acknowledges First Nations peoples' connection to land and water for more than 60,000 years, and the opportunity to mutually benefit from Australia's energy transition.

The 2023 Inputs, Assumptions and Scenarios Report forms a core input to this draft plan. The analysis that underpins the Draft 2024 ISP takes into account many factors, including developments in government policies, technology and investment settings. For example, since the 2022 ISP was published, the Commonwealth has released its Rewiring the Nation policy, and its Capacity Investment Scheme and the National Energy Transformation Partnership to support the large volume of energy-transition investment required. The plan's actionable projects also consider state and territory government scheme frameworks.

A recent change to the national electricity law requires that AEMO plans the power system in a way that helps achieve government targets that reduce greenhouse gas emissions, while being secure, reliable and cost-effective. This has been incorporated into the Draft 2024 ISP.

Australians' own investments in domestic rooftop solar systems are a valuable resource, and this draft plan highlights how they can make a significant contribution to the NEM.

Community support is critical to enable timely and cost-effective investments in the power system. Gaining the trust of regional and rural communities is essential to avoid the risk of essential infrastructure not being built before coal-fired generators close.

I would like to thank everyone who has been involved in the preparation of this draft ISP, and look forward to your feedback.

Daniel Westerman
Chief Executive Officer

Contents

Executive summary

A plan for investment in the energy transition

Australia needs an energy system that delivers secure, reliable and affordable electricity. In the past, we have depended on coal-fired generation. Now, the way Australia generates electricity is changing – from fossil-fuelled to renewable energy.

With coal retiring, renewable energy connected with transmission, firmed with storage and backed up by gas-powered generation is the lowest cost way to supply electricity to homes and businesses throughout Australia's transition to a net zero economy.

Governments have set 2050 as the target for a net zero economy, with each jurisdiction having interim emissions and renewable energy targets to meet that deadline. Federal Government policy is a 43% reduction in 2005-level emissions by 2030, with 82% of electricity in the National Electricity Market (NEM) supplied from renewable sources.

The energy transition, well underway, is by far the biggest transformation of the NEM since it was formed 25 years ago. As well as the shift from coal to firmed renewables, it will treble capacity to meet future demand, and enable a two-way flow of electricity across the grid.

Published every two years, AEMO's *Integrated System Plan* (ISP) is a roadmap for the transition of the NEM power system, with a clear plan for essential infrastructure to meet future energy needs.

Previous iterations of the ISP set an ambitious pace for investment. Projects now need to be delivered, as planned. About 90% of the NEM's coal fleet is forecast to retire before 2035 in AEMO's most likely future scenario, and the entire fleet before 2040.

This Draft 2024 ISP is a milestone on an industry-wide journey to prepare the ISP. It reflects consultations with consumer and community representatives, governments, energy market authorities, investors and developers, network planners, industry bodies and science and technology institutions.

The Draft 2024 ISP is a robust plan that calls for urgent investment in generation, firming and transmission that targets secure, reliable and affordable electricity through the energy transition, with its transmission elements delivering $17 billion in net market benefits to consumers.

- The energy transition is already well underway, breaking renewable generation records while managing inherent tensions. The ISP is a roadmap to complete the NEM's transition (Part A).
- The ISP's optimal development path sets out the needed generation, firming and transmission, which would deliver significant net market benefits for consumers and economic opportunities in Australia's regions (Part B).
- The transition is urgent, and faces significant risks if market and policy settings, social licence and supply chain issues are not quickly addressed (Part C).

AEMO welcomes feedback on this Draft 2024 ISP by 16 February 2024. Stakeholder feedback will inform the final 2024 ISP due for release by 28 June 2024.

An essential transition is well underway

The ISP is a roadmap through an energy transition that is already well underway, breaking renewable generation records while managing inherent tensions.

Australia's energy transition is essential. The NEM must almost triple its capacity to supply energy by 2050 to replace retiring coal capacity and to meet increased electricity consumption. Coal-fired generators, the ageing workhorses of Australia's electricity supply, are now retiring. They are less reliable, more difficult to maintain, and less competitive against firmed renewable supply. Households will be more energy efficient and draw considerably from batteries and rooftop solar, but will also need more electricity for appliances and especially for electric vehicles. Businesses and industry will double their grid electricity consumption to serve a growing, decarbonising economy, and for green energy products such as hydrogen.

The shift to renewables is well underway. Renewables accounted for almost 40% of the total energy delivered through the NEM in the first half of 2023, momentarily reaching up to a 72.1% share on 24 October 2023. Rooftop solar alone contributed more electricity to the grid in the first quarter of 2023 (12.1%) than did grid-scale solar, wind, hydro or gas. At the same time, investments in grid-scale renewables, connecting transmission and firming technologies continue to gain momentum.

All NEM governments are supporting the transition. The Federal Government has expanded the Capacity Investment Scheme. New South Wales' Electricity Infrastructure Roadmap is underpinned by its renewable energy zones (REZs). Queensland's SuperGrid and pumped hydro energy storage feature in its Energy and Jobs Plan. South Australia is now pursuing a Hydrogen Jobs Plan, and Tasmania has long had strong renewable energy targets. Victoria has set its Transmission Investment Framework and Renewable Energy and Storage Targets and is now including offshore wind towards its renewable energy targets, with explicit offshore wind development targets as well.

It will have undeniable benefits. Lower cost, lower emission renewables will offer homes and businesses the electricity they need, with greater insulation from international price shocks. NEM regions are forecast to need over 70,000 people in jobs to build and maintain the new infrastructure over the next 20 years. Australia may also develop new opportunities for lower-emission exports in hydrogen, data services, agriculture, aluminium and steel production and minerals processing.

But the transition is complex, with four inherent tensions to be managed. The NEM must operate safely and reliably today while being refitted for tomorrow. It must integrate new technologies piece by piece while keeping the whole system stable. It must deliver reliable and affordable electricity for the population, while addressing the concerns of people that host new infrastructure. And Australia must see its transition through as the rest of the world also races to decarbonise.

Determining the path for the future

AEMO takes all these matters into account. The ISP modelling approach integrates four separate analytical models to find the optimal mix of generation, storage and transmission. The objective is to determine an 'optimal development path' (ODP) that will meet the system's reliability and security needs and supports government emissions reduction policies[1] in the long-term interests of consumers. The ODP sets out the optimal size, place and timing for the NEM's future assets. AEMO considered over 1,000 potential development paths in all, narrowing them down to the 18 'candidate' development paths, which included the option of generation development with no additional transmission at all.

Candidate paths were tested against three future scenarios, through to 2050:

- *Step Change*, which fulfils Australia's emission reduction commitments in a growing economy,
- *Progressive Change*, which reflects slower economic growth and energy investment, and
- *Green Energy Exports*, which sees very strong industrial decarbonisation and low-emission energy exports.

All three scenarios acknowledge that coal will continue to retire over the coming years, and all three scenarios align with government net zero commitments.

After extensive consultation, AEMO has assigned likelihoods of 43% for *Step Change*, 42% for the similar *Progressive Change* and 15% for *Green Energy Exports*. This took in the views of over 30 expert panellists representing industry, government, network service providers, researchers, academics, and consumers. *Step Change* therefore is the ISP's most likely scenario.

The leading candidate paths were tested against changes in scenario assumptions. Some of these tests looked at greater electricity demand in the NEM and other influences which would increase the benefits of transmission (more rapid industry decarbonisation, faster coal retirements, reduced energy efficiency). Others considered slower delivery of infrastructure and other influences which would reduce the benefits of transmission (higher costs of capital, more constrained supply chains, weaker host community acceptance for new infrastructure).

The optimal development path is the lowest cost, resilient, pragmatic path to the NEM's energy future. The potential development paths included different balances between generation, storage and transmission. AEMO has consulted extensively to prepare the inputs, assumptions and scenarios used to develop the optimal development path. Alternative paths result in higher consumer costs, and many substantially so, and demonstrate less robustness to the uncertainties anticipated in this transition. Future ISPs will continue to respond to material changes in technologies, costs and policies.

Coal is retiring, faster than announced

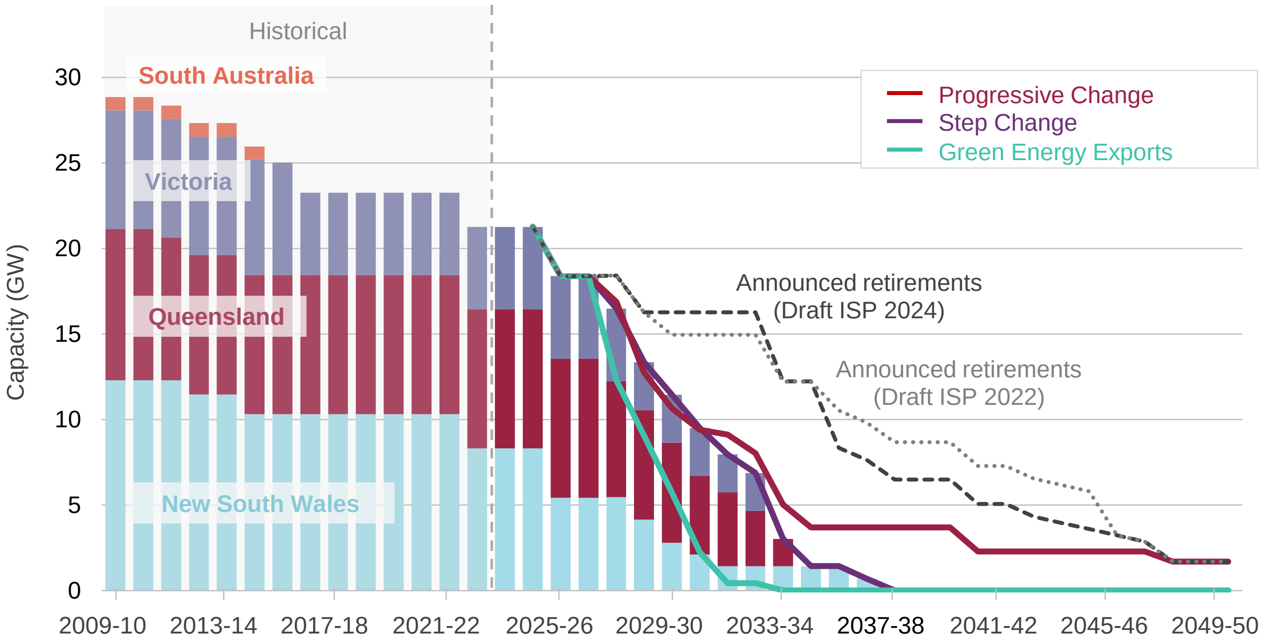
Ten large coal-fired generators have closed since Munmorah ceased operations in 2012, the latest being Liddell this year. Retirements have been announced for all but one of the remaining fleet, with about half by 2035 and the rest by 2051, continuing the steady rate of retirement since 2012: see Figure 1.

[1] In November 2023 a new emissions reduction element came into force in the National Electricity Objective (NEO) of the National Electricity Law. AEMO has chosen to apply the amended NEO in its preparation of the Draft 2024 ISP, by using only scenarios that comply with Australian governments' emissions reduction policies and by considering policies and targets in the Australian Energy Market Commission's *Emissions Targets Statement,* including those which are on their way to meeting (but have not yet met) the National Electricity Rules requirements for public policies' inclusion in the ISP.

However, the ISP forecasts that the remaining coal fleet will close two to three times faster than those announcements. In the most likely *Step Change* scenario, about 90% of the current 21 gigawatts (GW) of coal capacity would retire by 2034-35, and all before 2040. Even in *Progressive Change*, only 4 GW of coal generation would remain in 2034-35.

Coal retirements may occur even faster than these forecasts. Ownership has become less attractive, with higher operating costs, reduced fuel security, high maintenance costs and greater competition from renewable energy in the wholesale market. Coal owners are only required to give three and a half years' notice of a closure, which gives very little time for the NEM to react. Replacement capacity must be put in place well in advance.

Figure 1 Coal capacity, NEM (GW, 2009-10 to 2049-50)

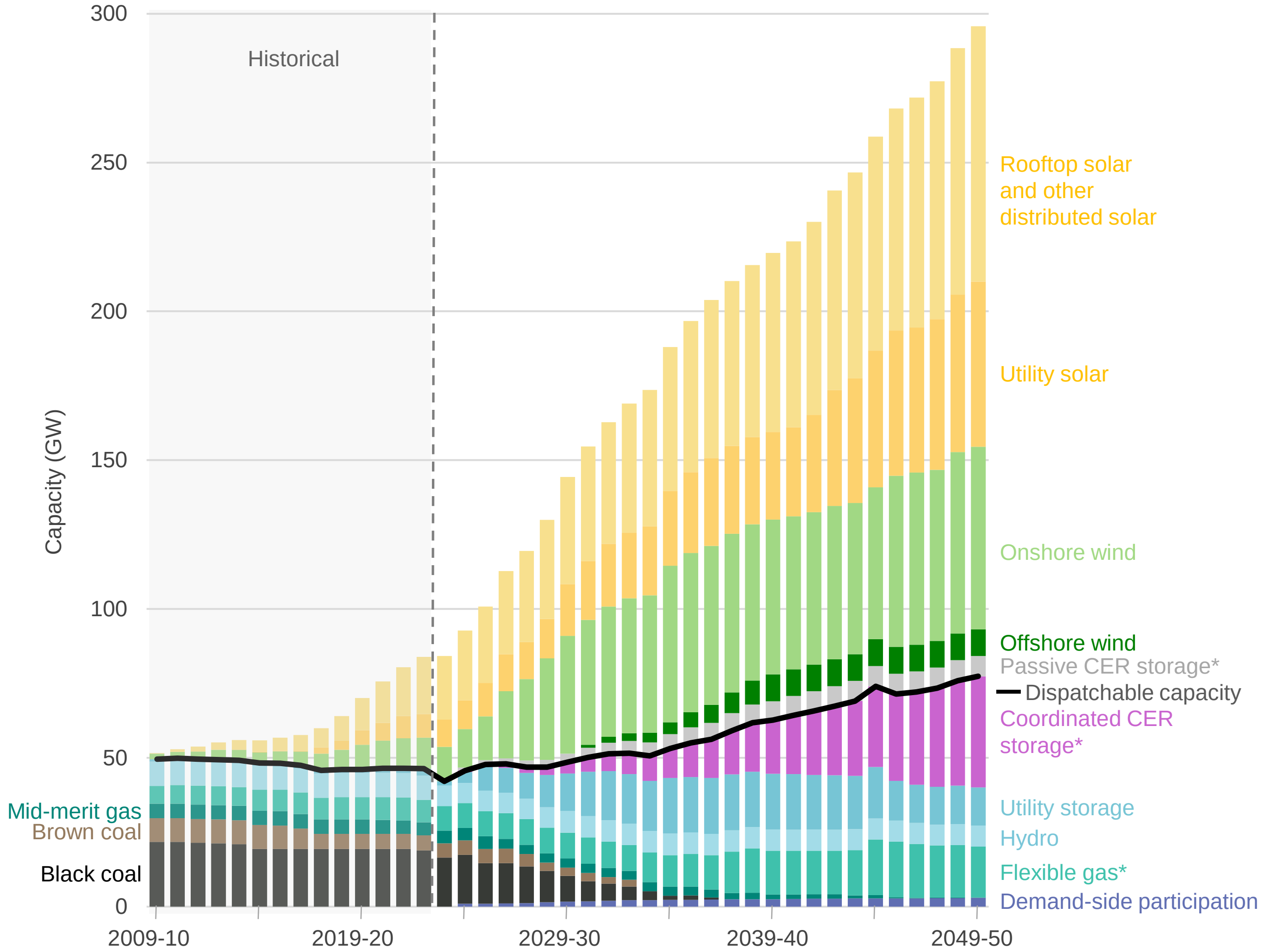


Generation and storage investments in the optimal development path

With coal retiring, renewable energy connected with transmission, firmed with storage and backed up by gas-powered generation is the lowest cost way to supply electricity to homes and businesses throughout Australia's transition to a net zero economy.

- Low-cost renewable energy will take advantage of the abundant wind, solar and hydro resources that Australia has to offer,
- Firming technology like pumped hydro, batteries, and gas-powered generation will smooth out the peaks and fill in the gaps from that variable renewable energy,
- New transmission and modernised distribution networks will connect these new and diverse low-cost sources of generation to our towns, cities and industry, and
- Upgraded power systems will be capable of running, at times, entirely on renewable energy.

Figure 2 Capacity, NEM (GW, 2009-10 to 2049-50, *Step Change*)



Notes: Flexible gas includes gas-powered generation, and potential hydrogen and biomass capacity.
"CER storage" are consumer energy resources such as batteries and electric vehicles.

AEMO has selected an optimal development path that sets out the capacity of new generation, firming, storage and transmission needed in the NEM through to 2050. Under forecasts for the *Step Change* scenario, the ODP calls for investment that would:

- **Triple grid-scale variable renewable energy by 2030, and increase it seven-fold by 2050**. About 6 GW of capacity would need to be added every year, compared to the current rate of almost 4 GW. Wind would dominate installations through to 2030, complementing installations of rooftop solar systems, and by 2050 grid-scale solar capacity would be 55 GW and wind 70 GW.
- **Focus grid-scale generation in REZs,** selected to access quality renewable resources, existing and planned transmission, and a skilled workforce. REZs will support better grid reliability and security; reduce transmission, connection and operation costs for individual assets; and promote regional expertise and employment at scale.
- **Almost quadruple the firming capacity** from sources alternative to coal that can respond to a dispatch signal, using utility-scale batteries, pumped hydro and other hydro, coordinated consumer energy resources as "virtual power plants" (VPPs), and gas-powered generation.

This includes 50 GW / 654 gigawatt hours (GWh) of dispatchable storage, as well as 16 GW of flexible gas.

- **Support a four-fold increase in rooftop solar capacity** reaching 72 GW by 2050, and facilitating the use of consumer-owned batteries and VPPs to deliver 27 GW of flexible demand response for the NEM.
- **Leverage system security services and operational approaches** to ensure that the NEM stays reliable and secure even as the renewable share of generation approaches 100%, as identified in AEMO's *Engineering Roadmap to 100% Renewables*.

The resulting NEM capacity through to 2050 is shown in Figure 2 on the previous page.

Transmission investments in the optimal development path

Transmission connects diverse generation and storage to our towns, cities and industry. It brings electricity where it is needed, when it is needed, and improves the power system's resilience. Transmission planners make the most of the existing network before considering new projects, for example by using real-time weather monitoring to maximise line use. In many cases, new transmission will complete a network that can take advantage of the NEM's geographic diversity, allow REZs to transfer their future energy to where it is needed, and maintain a secure and reliable power system.

Close to 10,000 km of transmission would be needed by 2050 under the *Step Change* and *Progressive Change* scenarios. If Australia is to pursue the more transformational *Green Energy Exports*, then over twice as much transmission would be needed, delivered at a much faster pace.

The ODP contains largely the same major projects as in the 2022 ISP. Five committed and anticipated projects are well underway for delivery. Five previously actionable projects remain actionable and are advancing, and two future projects have now progressed to actionable status as planned. There is a clear need for urgent delivery of all actionable transmission projects.

Table 1 and Figure 3 on the following pages set out the:

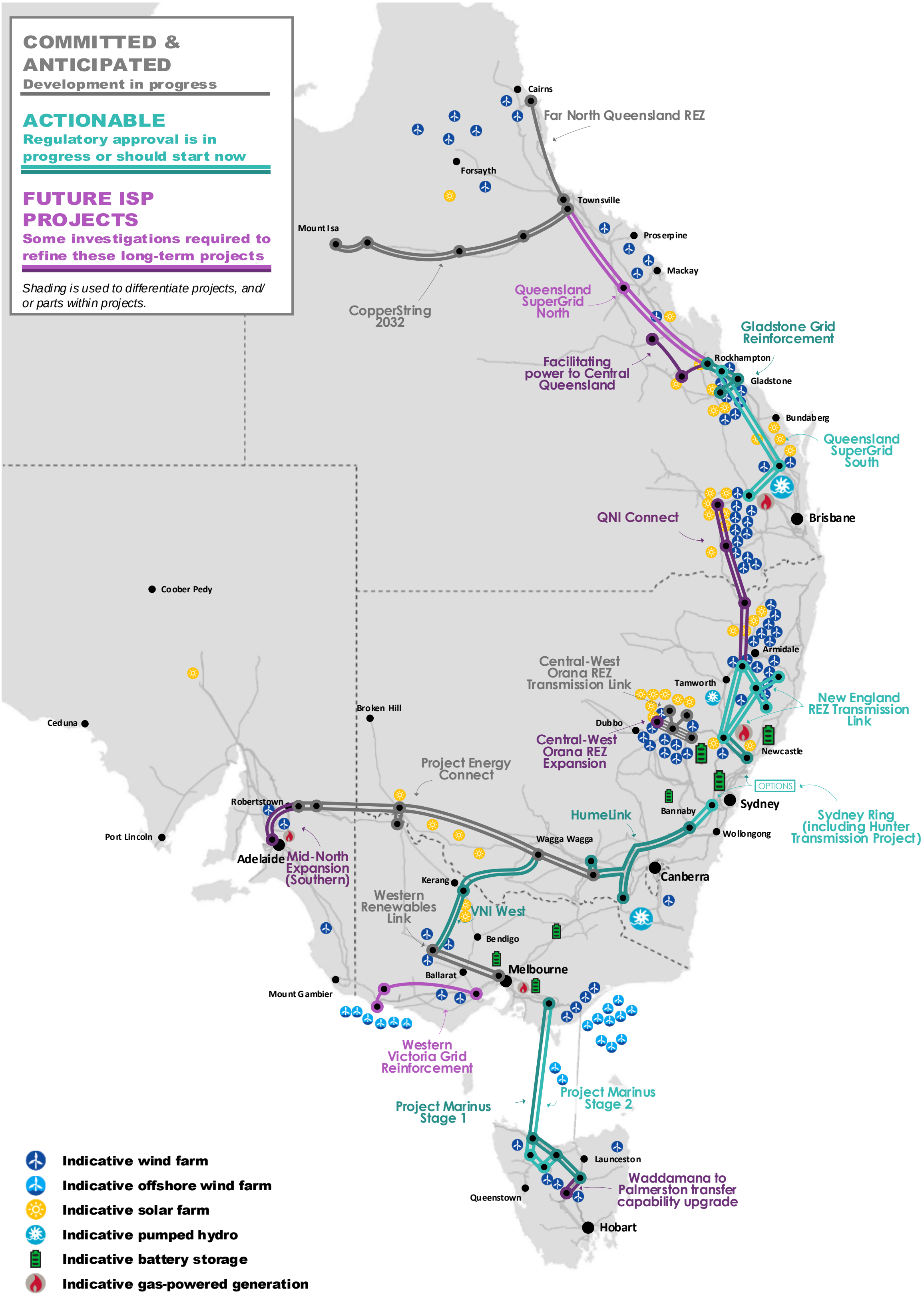
- **committed and anticipated transmission** projects already underway,
- **actionable projects**, for which work should continue and/or commence urgently, and
- **future ISP projects**, which may include the need for the transmission network service providers (TNSPs) to undertake preparatory activities.

Table 1 Network projects in the Draft 2024 ISP optimal development path

Committed and anticipated ISP projects		In service timing advised by proponent	Full capacity timing advised by proponent
Far North Queensland REZ		April 2024	April 2024
Project EnergyConnect[A]		Stage 1 April 2024 Stage 2 December 2024	Stage 1 July 2024 Stage 2 July 2026
Western Renewables Link		July 2027	July 2027
Central West Orana REZ Transmission Link		January 2028	August 2028
CopperString 2032[B]		June 2029	June 2029
Already actionable projects ***(confirmed in this Draft ISP)***	**Actionable framework**	**In service timing advised by proponent**	**Full capacity timing advised by proponent**
HumeLink[C]	ISP	Northern Circuit July 2026 Southern Circuit December 2026	Northern Circuit July 2026 Southern Circuit December 2026
Sydney Ring *(Hunter Transmission Project and investigation of southern network options)*	NSW[D]	December 2027	December 2027
New England REZ Transmission Link	NSW[D]	September 2028	September 2028
Victoria – New South Wales Interconnector West (VNI West)	ISP	December 2028	December 2029
Project Marinus[E]	ISP	Stage 1 June 2030 Stage 2 June 2032	Stage 1 December 2030 Stage 2 December 2032
Newly actionable projects ***(as identified in this Draft ISP)***	**Actionable framework**	**In service timing advised by proponent**	**Full capacity timing advised by proponent**
Gladstone Grid Reinforcement[F]	QLD[G]	September 2029	September 2029
Queensland SuperGrid South[F]	QLD[G]	June 2031	June 2031
Future ISP projects			
Interconnectors	Queensland – New South Wales Interconnector (QNI Connect)		
New South Wales	Central West Orana REZ Expansion, Hunter-Central Coast REZ Expansion, Cooma-Monaro REZ Expansion.		
Queensland	Darling Downs REZ Expansion, Facilitating Power to Central Queensland, North Queensland Energy Hub Uplift, Queensland SuperGrid North.		
South Australia	Mid North REZ Expansion.		
Tasmania	Waddamana to Palmerston transfer capability upgrade, North West Tasmania REZ Expansion.		
Victoria	Western Victoria Grid Reinforcement, Eastern Victoria Grid Reinforcement.		

A. The capacity release and timing is conditional on availability of suitable market conditions and good test results.
B. CopperString 2032 will be built and owned by the Queensland Government, continuing the commitment made through the Queensland Energy and Jobs Plan that all the state's transmission assets will be 100% publicly owned. This project was not actioned through the ISP framework.
C. 'Northern Circuit' is between Bannaby and Gugaa. 'Southern Circuit' is between Bannaby and Maragle, and Maragle and Gugaa. Transgrid has advised the Southern Circuit has been programmed to December 2026 for optimal delivery.
D. These are actionable New South Wales projects. They will progress under the *Electricity Infrastructure Investment Act 2020* (NSW) rather than the ISP framework. New England REZ Transmission Link includes additional scope compared to 2022 ISP, with the proponent date only applying to the original scope.
E. Project Marinus includes MarinusLink and North West Transmission Developments (NWTD) projects. Project proponent dates represent modelling dates and are under negotiation. Stage 1 refers to Cable 1 and associated NWTD works, and Stage 2 refers to Cable 2 and associated NWTD works. Project Marinus is a single actionable ISP project without decision rules.
F. Project proponent dates are subject to further refinement.
G. These are actionable Queensland projects. They may progress under the *Energy (Renewable Transformation and Jobs) Bill* 2023 (Qld) rather than the ISP framework.

Figure 3 Transmission projects in the optimal development path



This map shows indicative new generation and storage in 2040, and transmission projects that include new transmission lines, increase capacity by 1,000 MW or more, and are required in all scenarios by 2050.

Benefits of the optimal development path

The selected ODP sets out the capacity of new generation, firming, storage and transmission needed in the NEM through to 2050. It would:

- guide the capital investment needed for essential electricity infrastructure to sustain and grow Australia's $2 trillion annual economy
- avoid $17 billion in additional costs to consumers (in present value terms) if no transmission was included in this capital investment
- connect emerging areas of renewable generation to regional industries and to urban businesses and households
- firm variable renewable energy with batteries, hydro and gas-powered powered generation, and
- create new economic and job opportunities, particularly in regional areas.

The annualised capital cost of all generation, storage, firming and transmission infrastructure in the ODP has a present value of $121 billion (*Step Change* scenario to 2050)[2]. The equivalent upfront capital cost has a present value of $138 billion (as some technical life remains after 2050 for the long-lived assets). Of the annualised cost, transmission projects amount to $16.4 billion[3] or 13.5% of the total. They would pay themselves back and deliver the additional $17 billion net market benefit noted above.

Risks to delivery of the ODP and to the energy transition

AEMO has identified the ODP as the most effective path to maintain reliable electricity supply as coal retires and to deliver the energy system needed for a net zero economy. Any delay to delivery of the ODP increases the likelihood of interruptions and higher costs.

While significant progress is being made, challenges and risks are already being experienced. Unplanned coal generator outages are becoming more common as the fleet ages. Planned projects are not progressing as expected, due to approval processes, investment decision uncertainty, cost pressures, social licence issues, supply chain issues and workforce shortages.

The possibility that replacement generation is not available when coal plants retire is real and growing, and a risk that must be avoided. The sooner firmed renewables are connected, the more secure the energy transition will be.

Risks that market and policy settings are not yet ready for coal's retirement

Four sets of market and policy settings need to be in place if the NEM is to keep the energy transition on track, and in particular be ready for coal generator retirements.

[2] This value does not include the cost of commissioned, committed or anticipated projects.

[3] This value is the net present value of capital costs for transmission augmentation up to 2049-50 only.

Risk of uncertainty for infrastructure investment

The energy transition depends on timely investment decisions, which are hampered by uncertainty. Government initiatives such as Long-Term Energy Service Agreements in New South Wales, state-based renewable energy and infrastructure targets, the Capacity Investment Scheme and the Nationally Significant Transmission Project framework help reduce that uncertainty. AEMO strongly supports further market reforms that will expedite investment and effectively balance timely investment with assessment rigour across all forms of infrastructure.

Risk of early coal retirements

While almost all owners of coal generators have announced their long-term retirement plans, they are only required to give three and a half years' notice of a closure, which would leave the NEM very little time to respond. Closures with short notice increase the risk of near-term reliability challenges and price shocks for consumers, and further accelerate the need for new generation. These risks are best mitigated through agreed latest closure timeframes and delivery of the planned investment in generation capacity.

Risk that markets and power system operations are not yet ready for 100% renewables

Renewable generation is being installed rapidly, but the NEM's energy markets, networks and operations must evolve to be ready for very high penetrations of renewable energy. More action is needed to make sure that system services, resource adequacy and operational capability are in place in time for coal retirements.

AEMO continues to work with governments, market bodies and industry on the technical requirements for a secure power system capable of operating at 100% renewables, and subsequent evolution of market frameworks and settings to deliver those requirements in both investment and operational timeframes.

Risk that consumer energy resources are not adequately integrated into grid operations

Consumer-owned assets offer significant system benefits and offset the need for grid-scale investment. These benefits would be foregone unless two steps are taken. First, that consumer-owned assets are grouped together and coordinated as virtual power plants (VPPs) to respond to market or network signals. Then, that the VPPs are appropriately integrated into the NEM to help support power system reliability and security. Owners would need to see the benefits of both actions, and trust the energy sector to deliver them. AEMO will continue working with governments, market bodies and consumer groups for these benefits to be realised.

Risks that social licence and supply chains are not secured for project delivery

The policy, market and operational settings noted above are largely in the hands of governments and the energy industry. Even if they are in place, the ODP and the energy transition would not be guaranteed.

To deliver the transition on time, industry and governments must work together with communities throughout the NEM to ensure there is the needed social acceptance, with global supply chain partners to secure equipment and materials, and with governments in Australia to secure the workforce needed.

Risk that social licence for the energy transition is not being earned

Community acceptance or social licence is needed for new infrastructure development, for the 'orchestration' of consumer-owned energy resources, and for national investment in the energy transition itself. NEM affordability and reliablity is essential for community acceptance on each of these dimensions.

Energy institutions, developers and communities are working hard to build the relationships of trust that underpin social licence. Their experience is being captured by the National Guidelines for Social Licence for Transmission, the Australian Energy Infrastructure Commissioner's review of community engagement practices, the Victorian Transmission Investment Framework (VTIF), and the New South Wales First Nations Guidelines for consultation and negotiation with local Aboriginal communities, among other initiatives. These and like initiatives are critical to building the trust-based relationships needed for the energy transition.

AEMO is working with its Advisory Council on Social Licence to better understand new and diverse perspectives, to develop new analyses that account for levels of social acceptance for the ISP.

Risk that critical energy assets and skilled workforces are not being secured

The energy transition depends on thousands of grid-scale generators and batteries, high voltage transmission lines and cables, synchronous condensers and transformers. Australia needs to be able to access these assets over the next 15 years in particular. Countries around the world are competing for these assets as they transform their power systems in the global race to net zero.

Similarly, a large and skilled workforce is needed for the enormous task ahead. The demand for energy sector workers is forecast to grow from approximately 40,000 people in 2023 to a peak of over 70,000 by 2050, in the *Step Change* scenario. This workforce is needed across every discipline, not just engineering.

Early investment will mitigate against supply chain risks in future, retain Australia's spot in global queues for essential equipment and materials, and ensure the NEM is able to respond to future market and climate events.

AEMO will continue to work with all industry organisations to ensure a secure, reliable, affordable energy future for Australia.

Invitation for submissions on the Draft ISP

Drawing on extensive consultation over the past 18 months, the Draft 2024 ISP provides a roadmap for the transition of the NEM power system, with a clear plan for essential infrastructure to meet future energy needs, balancing consumer risks and benefits in their long-term interests.

All stakeholders are invited to provide a written submission on the Draft 2024 ISP, which should be sent in PDF format to **ISP@aemo.com.au** by 6pm (AEST) on Friday, 16 February 2024.

The consultation questions are:

1. Does the proposed optimal development path help to deliver reliable, secure and affordable electricity through the NEM, and reduce Australia's greenhouse gas emissions? If yes, what gives you that confidence? If not, what should be considered further, and why?
2. Does the proposed timing and treatment of actionable projects support a reliable, secure and affordable NEM? If yes, what gives you that confidence? If not, what should be considered further, and why?
3. Does the Draft 2024 ISP accurately reflect consumers' risk preferences? If yes, how so? If not, how else could consumers' risk preferences be included and what risks do you think are important to consider?
4. Do you have advice about how social licence can be further considered in the ISP, or advice on how to quantify the potential impact of social licence through social licence sensitivity analysis?
5. Do you have any feedback on the *Addendum to the 2023 Inputs Assumptions and Scenarios Report*?

AEMO thanks all stakeholders for their advice and input so far, and looks forward to continuing to consult with consumers, industry and other stakeholders to finalise the 2024 ISP.

Key changes from the 2022 ISP

The Draft 2024 ISP sets out how AEMO has identified the optimal development path (ODP) for the NEM. The ISP is adjusted as economic, physical and policy environments change. AEMO notes the following key differences between the 2022 ISP and this Draft 2024 ISP.

Changes to the overall framing of the ODP

- **None** – AEMO continues to find that renewable energy connected with transmission, firmed with storage and backed up by gas-powered generation is the lowest cost way to supply reliable electricity to homes and businesses throughout Australia's transition to net zero.

Updates to inputs, assumptions and scenarios used to analyse the ODP

- **Stronger emissions reduction policies now apply**, with Australia's Paris Agreement commitment increased to 43% emissions reduction by 2030 and the complementary Powering Australia Plan for an 82% share of renewable generation by 2030.
- **AEMO's refined scenario set reflects significant expansions in commitments to net zero**. AEMO's *Step Change*, *Progressive Change* and *Green Energy Exports* scenarios all align with the updated commitments. *Step Change* is considered 'most likely' and features an energy transition pace to less than 2°C and compatible with 1.5°C outcomes depending on the actions taken across other sectors.
- **Consumer energy resources are forecasted to be taken up even faster than before**, with 18 GW more rooftop solar by 2050 under *Step Change* compared to the 2022 ISP.
- **Higher costs for transmission, generation and storage** have been observed in recent years due to supply chain issues and workforce shortages, including around 30% increases for transmission projects. AEMO expects that transmission project costs will continue to increase beyond the rate of inflation as the sector adapts to market pressures and to account for environmental and land costs.

Further analysis to inform the ODP

- **Sensitivity analysis considering the impact of low social licence** on the development opportunities and transmission network developments considered in the ISP.
- **Analysis considering the impact of gas system capacity limitations** on the operation of gas-fired generation during peak periods.
- **Investigation of consumer risk preferences** through in-person focus groups and an online survey, finding that in general consumers are open to some prudent infrastructure investment now to manage the risk of future price shocks – although this needs to be weighed carefully against any near-term bill impact.

Changes to the speed or scale of the ODP

- **The entire coal fleet in the NEM is retired by 2038 in *Step Change*** in this Draft 2024 ISP, five years earlier than in the 2022 ISP.
- **Earlier need for renewable energy** with a need for 6 GW of new renewable energy per year under *Step Change* in the coming decade, compared to 4 GW in the 2022 ISP (and a current

rate of almost 4 GW[4]). This is to replace the coal generation capacity that is exiting faster and to meet the higher demand forecast compared to the 2022 ISP.

- **Increased need for dispatchable supply and a shift towards consumer-owned storage.** The Draft 2024 ISP increases backup gas-powered generation capacity to 16 GW by 2050, up from 10 GW in the 2022 ISP. The forecast need for medium-depth storage has reduced by 5 GW due to increased wind generation and increased storage capacity from consumer energy resources.
- **The 2023 *Progressive Change* scenario acknowledges more rapid change due to new policies, and is now considered almost as likely as *Step Change*.** However, the near-term need for projects across the NEM is common to both scenarios, with only two actionable projects required slightly later in *Progressive Change* than *Step Change*.

Changes to investment in the ODP

- **Net market benefits of transmission investment have reduced by 37 percent**, from $27.7 billion in the 2022 ISP to $17.45 billion. Factors include increased transmission costs, generator and storage costs, updated energy policies, commitment to transmission projects whose benefits are now assumed and not included in the total, and lower gas prices.
- **The need for new transmission network is broadly the same over the coming decade**. Beyond the next decade, the ODP sees slightly less transmission build than the 2022 ISP, due to higher transmission costs, the optimisation of project options, and more generation from sources that need less transmission.
- **More offshore wind in Victoria** and **more pumped hydro (and supporting transmission) in Queensland** in line with State policies.
- **Transmission projects have progressed across the NEM:**
  - **Some planned projects have been completed** and are now operational, including Queensland – New South Wales Interconnector Minor upgrade (QNI Minor), Victoria – New South Wales Interconnector Minor upgrade (VNI Minor) and Eyre Peninsula Link.
  - **Newly committed or anticipated transmission projects,** such as CopperString 2032 and increased capacity planned for the Central West Orana REZ Transmission Link.
  - **Future ISP projects have become actionable projects**, as expected. In Queensland, SuperGrid South (formerly Central to Southern Queensland) and Gladstone Grid Reinforcement have become actionable. In New South Wales, the New England REZ Extension and further augmentation is now included as stages in the New England REZ Transmission Link project.

[4] This is generation which commenced operating at its full capacity.

PART A

The ISP is a roadmap through the energy transition

Part A: The ISP is a roadmap through the energy transition

As Australia's coal-fired generators retire after decades of service, renewable energy connected with transmission, firmed with storage and backed up by gas-powered generation (GPG) is the lowest cost way to supply electricity to homes and businesses.

In this Part A:

- **Section 1 – Australia's two-part energy transition will deliver significant benefits.** The National Electricity Market (NEM) is a complex system facing two challenges at the same time: the retirement of coal-fired generation, and the switch to electricity for our future transport, heating, cooling, cooking and industrial needs. If successful, the transition will bring multiple benefits.
- **Section 2 – The transition is well underway.** Consumers, investors and governments are rapidly turning to renewable energy. There are tensions that risk the pace of transition, but the direction is clear.
- **Section 3 – The *Integrated System Plan* (ISP) navigates the energy transition.** The ISP is a roadmap for the NEM power system, prepared in the long-term interests of electricity consumers. Through an exhaustive process, the ISP identifies an optimal development path (ODP) to secure reliable and affordable power for consumers and to meet emission reduction targets.

Part B follows to set out the generation, transmission, storage, gas and system services that will best meet the NEM's needs. Part C explores the risks currently faced by the energy transition, and the consultation needed on the Draft ISP.

1 The two-part energy transition and its benefits

Electricity is indispensable to our homes and businesses, and to the transport and communication networks we all rely on. All must have secure, reliable and affordable supply, and be confident it will be there when they need it.

The NEM has delivered that electricity for 25 years. It must now do so while coal generators are retiring, while electricity consumption is forecast to almost double, and in a way that contributes to our national and state emission reduction targets.

This section sets out how and why the NEM is being transformed:

1.1 **The NEM is switching to renewable energy.** Coal generators are retiring. The ISP finds that the lowest cost replacement is renewables, connected with transmission, firmed by storage, and backed up by gas-powered generation.

1.2 **The NEM will need to almost triple its generating capacity,** as variable renewable generation typically operates at less than full capacity. At the same time, industry, business and households will need more electricity as they switch from fuel and gas.

1.3 **There will be significant, diverse benefits.** These span greater insulation from international shocks, new jobs particularly in regional and rural areas, and lower emissions.

Section 2 follows to describe how the transition is well underway.

1.1 The essential shift to renewable energy

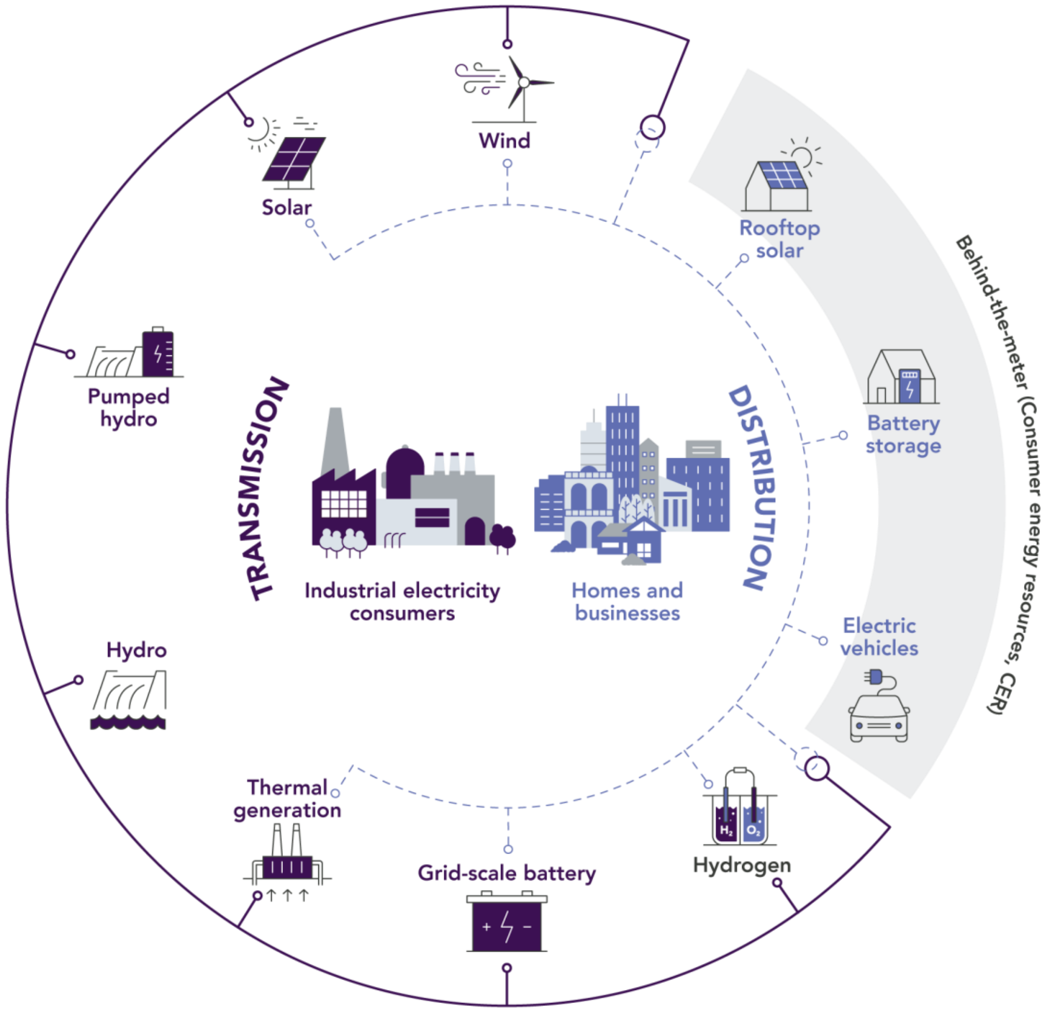
We rely on a complex power system

The NEM is an intricate system of systems, with regulatory, market, policy and commercial parts. At its centre is the physical system that delivers power when and where we need it.

Three types of consumers (heavy industry, business and households) have different needs when it comes to electricity. Figure 4 overleaf illustrates how the NEM meets those needs through generation, storage and transmission, and by supporting distribution and consumers' own energy resources.

Heavy industry like aluminium or iron smelters typically draw their electricity directly from the transmission grid. Business and household consumers have traditionally drawn their electricity from the distribution grid. Now, they are investing in their own 'consumer energy resources' (CER, that is, rooftop solar, batteries and electric vehicles (EVs)). Some EVs may themselves be able to discharge electricity for direct use, to household batteries, or back into the grid.

Figure 4 A power system with both grid and behind-the-meter energy supply



An energy transition is essential

Coal-fired generation has dominated Australia's electricity supply for generations. However, these workhorses are now ageing and becoming less and less reliable, more expensive and difficult to maintain, and less competitive against renewable electricity supply.

In the past decade alone, 10 major coal-fired power stations have retired, starting with Munmorah in 2012 through to Liddell in 2023. Reliability risks were exposed in June 2022, when 3 gigawatts (GW) of coal-fired generation was out of action – 13% of the NEM's coal capacity.

Households, business, industry and governments are also switching to electricity for their transport and energy needs, relying on the power sector to support their low-emission commitments and aspirations.

As coal retires it is being replaced by low-cost renewables, connected by transmission, firmed by storage, and backed up by gas. At the same time, consumers continue to invest in rooftop solar, with EVs and battery systems now becoming more common.

Renewables are not a like-for-like replacement for coal in many respects. A number of different investments are needed for a transition that maximises benefits to energy consumers:

- Low-cost solar and wind generation will take advantage of Australia's abundant solar and wind resources.
- Renewable energy zones (REZs) are being developed across the NEM to tap into high-quality wind and solar areas using economies of scale and providing new employment opportunities.
- Transmission networks, existing and new, will connect the renewable energy from REZs through to consumers, bringing low-cost electrons to heavy industry, businesses and households.
- Firming technologies will smooth out the variations in renewable supply: batteries for everyday variations, and strategic pumped hydro projects for longer-term and seasonal variations.
- Gas-powered generation will provide necessary back up with critical power supply when it is needed, both for 'renewable droughts' of 'dark and still' conditions, or to meet peaks in consumer demand.
- Batteries, gas and other network investments will deliver essential power system services to maintain grid security and stability.
- Rooftop solar and local batteries, connected to modernized distribution networks, will generate consumers' own electricity, store it for when they need it, and supply the excess back to the grid.

Doing all this at once is complex. Across the electricity sector, people are working on the operational and engineering solutions needed to support our transition to a high-renewables power system.

All the while, the priority is secure, reliable and affordable supply for Australian consumers.

1.2 Increasing electricity demand and consumption

The shift to renewable energy is the first part of the energy transition. Another is the great increase in demand for electricity, as consumers use it it for transport, heating, cooling and cooking. Even more electricity will be needed as hydrogen production and other new energy industries emerge.

The increase in demand for NEM electricity will be partially offset by consumers' own efforts. Households, businesses and industry are investing in their own energy assets, and their technologies and behaviours are becoming more energy efficient.

This section sets out how:

- Future energy consumption from the NEM will rise by approximately 108% by 2050, largely from business and industry, as households increasingly meet their own electricity needs.
- Future daily demand profiles show how solar energy needs to be stored for use later in the day.

Terminology for measuring consumers' use of electricity

AEMO uses the industry terms 'demand' and 'consumption' to refer to how much electricity use will be needed in the NEM:

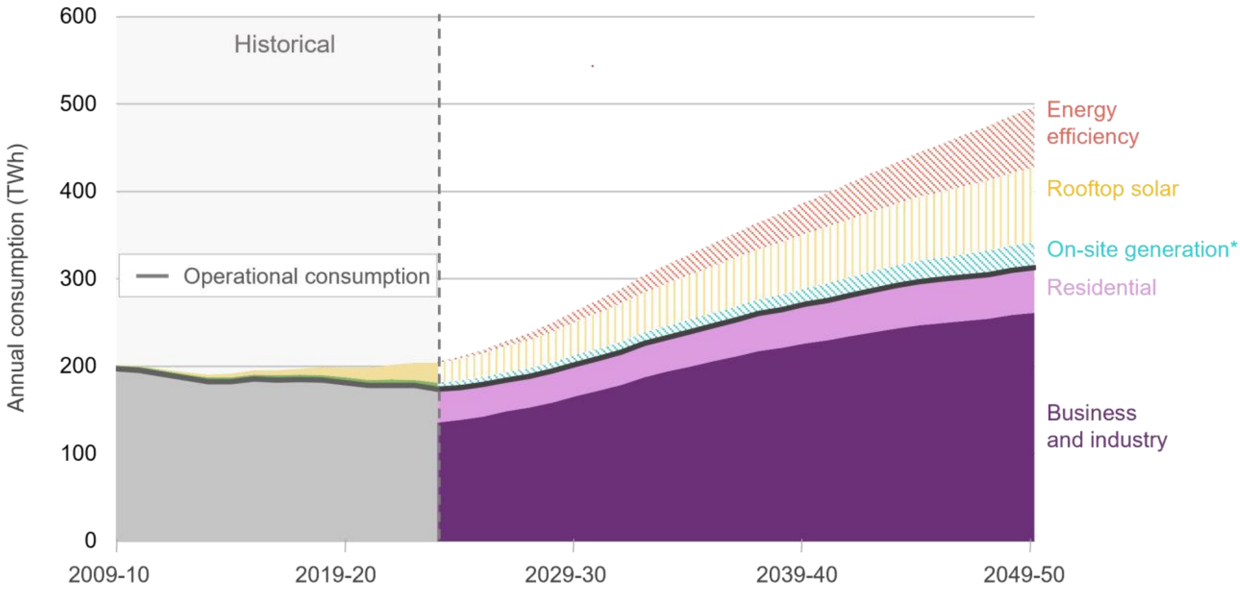
- **'Demand'** is the electricity needed **at a point in time**, expressed as 'kilowatts' (kW), megawatts (MW), gigawatts (GW) and terawatts (TW). Consumers may draw 21 GW of electricity from the grid at one time, and another 2 GW from their own 'behind-the-meter' resources. What the grid meets is 'operational demand', while the total 23 GW is the 'underlying demand'.
- '**Consumption**' is the total electricity used **over a period of time**, expressed as 'kilowatt hours' (kWh), megawatt hours (MWh), gigawatt hours (GWh) and terawatt hours (TWh). The underlying consumption across the NEM is about 200,000 GWh or 200 TWh. Allowing for 20 TWh supplied by consumer resources, the grid's annual operational consumption is currently about 180 TWh.

In this ISP, 'demand' means operational demand, and 'consumption' means operational consumption. These are what the NEM must deliver, reliably and affordably.

Future energy consumption

Overall, allowing for continued growth in energy efficiency, electricity consumption across the NEM is forecast to continue rising to over 410 TWh in 2049-50: see Figure 5. Growth in residential consumption is significantly offset by the uptake of rooftop solar and energy efficiency. Business consumption grows with the economy, its electrification, and the inclusion of hydrogen loads.

Figure 5 Electricity consumption, NEM (TWh, 2009-10 to 2049-50, *Step Change*)



Note: On-site generation (or "non-scheduled generation") is non-utility generation that includes on-the-ground PV and small wind and biomass, typically for industrial use.

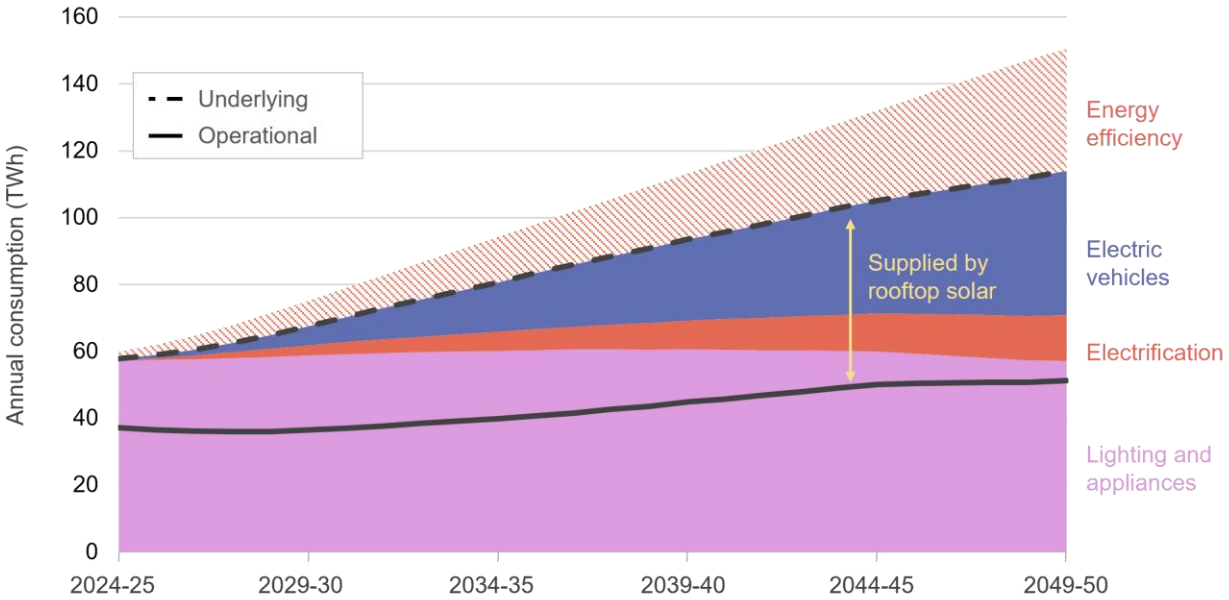
Residential consumption to stay flat

Taken as a whole, households are forecast to draw about as much from the grid across a year in 2050 as they do now. Their EVs and appliances will drive up underlying consumption, and be offset by their investments in rooftop solar and energy efficiency. Individual households will differ in how they rely on the grid. Many will continue to be without rooftop solar and draw electricity from the grid, while those with solar may export excess energy during the day and import from the grid overnight.

Figure 6 shows how electricity use for existing home lighting and appliances currently makes up almost all residential consumption. As households charge EVs and use more electricity for heating, cooling and cooking their total consumption increases to 150 TWh by 2050. However, uptake of energy efficient buildings, appliances and behaviour offsets this increase, resulting in underlying consumption of 115 TWh. Rooftop solar further reduces reliance on the grid to only 50 TWh across the year by 2050 – about the same as what it is today.

Households can draw electricity either direct from their rooftop solar, from the grid, from their household or community batteries, or even from EVs that are able to discharge their batteries. However, there will be big swings in demand across the day, as discussed below.

Figure 6 Residential electricity consumption, NEM (TWh, 2024-25 to 2049-50, *Step Change)*

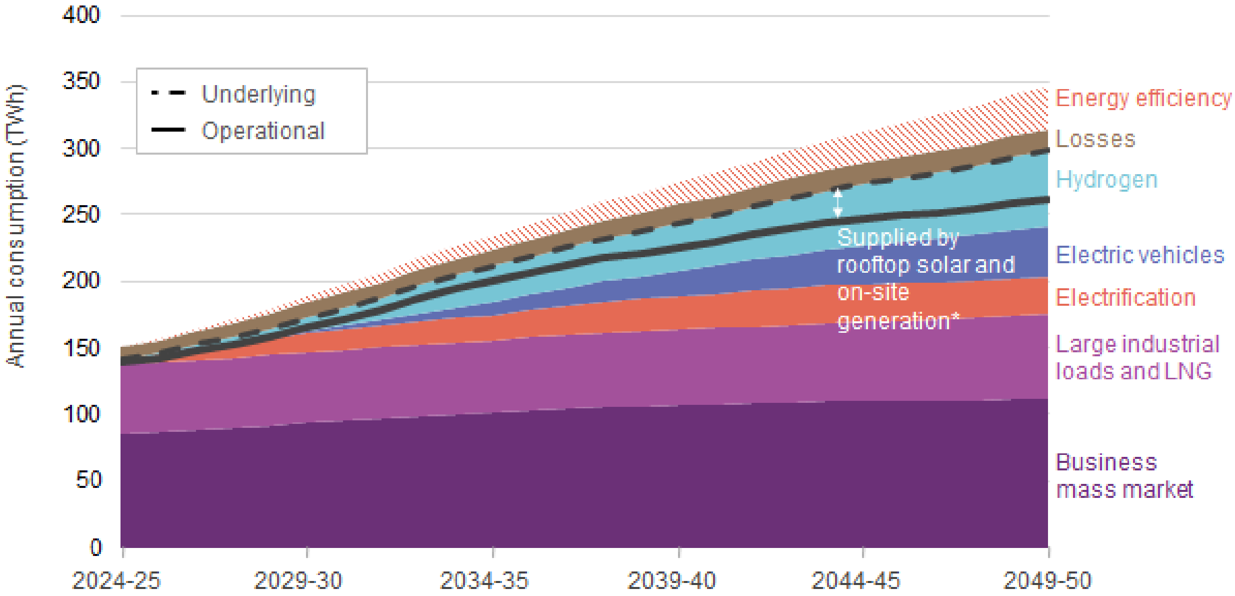


Business and industry consumption to almost double

Business and industry total consumption is forecast to more than double from today's 145 TWh to almost 345 TWh in 2050: see Figure 7 over page. Economic growth is expected to drive a 45 TWh rise, the switch of transport and industrial processes to electricity would add another 65 TWh, and emerging hydrogen would add at least 55 TWh. However, these new industrial consumers may be more flexible in the timing of their electricity demand, shifting production to take advantages of lower costs when supply is in surplus.

Investment in energy efficient processes and buildings will offset this increase, bringing underlying consumption to 300 TWh. On-site generation generation will further ease demand on the grid to 260 TWh.

Figure 7 Business and industry electricity consumption, NEM (2024-25 to 2049-50, *Step Change*)



Note: On-site generation (or "non-scheduled generation") is non-utility generation that includes on-the-ground PV and small wind and biomass, typically for industrial use.

Future daily demand profiles

The five-yearly lines in Figure 8 below show the daily variations that the NEM must manage for consumers. Forecast electricity demand keeps a similar daily shape (or 'profile') through to 2050, but rises for all times of the day. In summer, the evening peak is forecast to rise over time, while midday operational demand stays lower due to rooftop solar. In winter, reduced solar output and more demand for energy means that operational demand is higher throughout the day, rising throughout the transition, requiring greater NEM capacity.

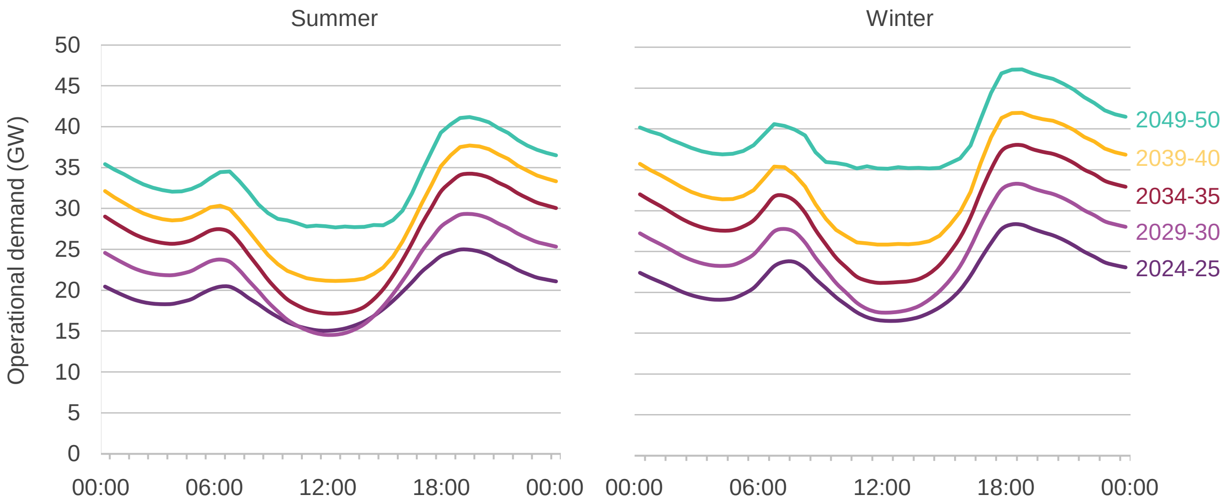
The ISP identifies the most efficient ways for the NEM to manage these midday lows and evening peaks. Consumers can also help smooth out the demand profile by drawing on their own assets and by choosing what time of day they use electricity.

- **Residential and commercial batteries** can be installed to soak up surplus daytime solar for discharge later in the evening, and aggregated as virtual power plants (VPPs).
- **EVs** can contribute by being charged outside the morning and evening peaks, preferably through the peak solar daylight. Owners may also discharge their EV's stored energy back to the home, or to the broader grid when needed.
- **Smart home management systems** may similarly control hot water systems and other appliances to take advantage of cheaper daylight electricity and avoid the more expensive peaks.

- **Large industrial users, including hydrogen production**, may be set to take most advantage of surplus renewable generation when it is available, particularly during daylight hours.

Batteries, VPPs and EVs can reduce even more grid demand if their charging and especially discharging can be integrated with the grid. This would reduce the need for more utility-scale investment: see Section 4.2.

Figure 8 **Average operational demand by time of day and season, NEM** (GW, 2024-25 to 2049-50, *Step Change*)



1.3 Significant and diverse benefits

The energy transition offers benefits that extend beyond reliable, affordable, low-emission electricity for the future. As a result of this investment, Australians are more likely to see:

- greater insulation from the international shocks that affect gas, petroleum and coal prices, and that put unwelcome pressure on the cost of living,
- reliable and affordable energy as increasingly expensive and unreliable coal-powered generation is replaced by renewables with far lower fuel, maintenance and operation costs,
- around 30,000 new jobs over the next 20 years to build the new infrastructure and to maintain and operate the energy system,
- a vast new economic opportunity for Australia – as the global economy seeks to reduce emissions, Australia will have new export opportunities in low-emission, energy-intensive industries: steel and aluminium, data warehouse services, green energy (hydrogen and ammonia) and critical mineral processing, and
- support for Australia's existing regional and rural economies, by providing lower-cost electricity and further opportunities for economic expansion.

These opportunities are both strong and attainable. While there is no guarantee that all benefits will flow in full, Australia is in a globally enviable position.

2 The transition is well underway

The energy transition is a once-in-a-century change to the way energy is generated, stored, moved, and used across the economy. Coal generators are retiring. The lowest-cost replacement is renewables, connected with transmission, firmed by storage, and backed up by gas-powered generation. Forecasts show the NEM power system needs to almost triple its installed capacity in less than 30 years.

This section sets out how:

2.1 **The transition is well underway.** Major coal plants continue to retire. Renewables delivered almost 40% of the NEM's total energy in the first half of 2023. Government policies for decarbonisation are in place and deepening, and consumers and business are investing in generation and storage.

2.2 **There are inherent tensions being managed**: today and tomorrow, the parts and the whole, people and populations, Australia and the world**.**

Section 3 then describes how AEMO has worked with consumers, the energy industry, governments and communities to set a clear plan for essential infrastructure to meet our future energy needs.

2.1 The transition is well underway

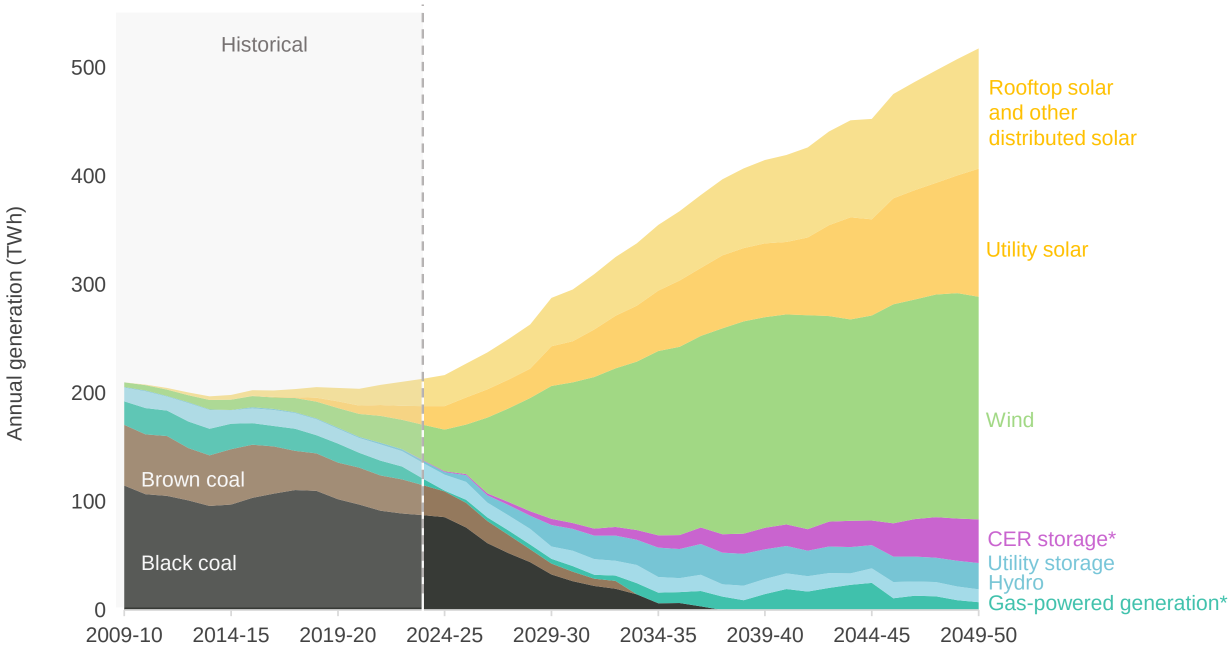
Australia is well underway in transforming its energy system. New investments in renewable generation and storage are accelerating, looking to keep ahead of coal closures and the big switch to electricity. Renewables accounted for almost 40% of the total energy delivered through the NEM in the first half of 2023. Government policies for decarbonisation are accelerating, network upgrades are underway, and consumers are investing heavily in their own resources.

The NEM has already reached 72% renewable

The level of renewable energy injected into the grid regularly sets new records. On 24 October 2023, 72.1% of total NEM generation came from renewable sources, a new record for a 30-minute period. At maximum available output from wind and solar generation, plus the actual dispatched output from other renewable sources, renewable potential represented 89.9% of the total NEM supply at that time (nearing the current record of 99.7% renewable potential observed on 1 October 2023).

Soon, AEMO will regularly face times when the power system is able to be supplied entirely by renewable energy, which will have implications for system security and strength. The NEM is among the first systems in the world facing the challenge of securely handling a high-renewables system. Figure 9 (over page) shows the past and forecast generation mix in the NEM, and indicates just how far through the transition we already are.

Figure 9 Generation mix, NEM (TWh, 2009-10 to 2049-50, *Step Change*)



Notes: Annual generation for 2023-24 has been estimated for the full financial year.
The forecasted gas-powered generation includes some potential hydrogen and biomass capacity.
"CER storage" are consumer energy resources such as batteries and electric vehicles.

Consumers are investing in their own resources

The growth in new rooftop solar systems has averaged 12% year on year over the past five years, reaching 3.1 million systems in 2023. Rooftop solar is now three times as common in Australia as backyard pools, and is capable of meeting 48% of underlying energy demand across the NEM in the middle of a sunny day. Rooftop systems contributed 12.1% of the NEM's total generation in the summer (Q1) of 2023, more than utility-scale solar (7.5%), wind power (11.6%), hydro (6.1%) and gas (4.6%)[5].

This is the first wave of consumer investment in their own energy transition. All-electric homes with batteries and rechargeable electric vehicles are gaining popularity. Early adopters are taking control of both their energy costs and their emissions footprint. Governments are encouraging these changes, with the ACT and Victoria phasing in bans of new residential connections to the gas system.

Government policies for decarbonisation are accelerating

All NEM state and federal governments are pushing to decarbonise the economy, and most have accelerated and strengthened their targets in recent years[6].

[5] AEMO. Quarterly Energy Dynamics Report Q1, April 2023. At https://www.aemo.com.au/energy-systems/major-publications/quarterly-energy-dynamics-qed.

[6] The emission reduction or renewable energy targets of any NEM participating jurisdiction have been a consideration in the National Electricity Objective from 21 November 2023. AEMO has included these policies if either their legislation or their funding arrangements are likely to be in place by the June 2024 publication of the 2024 ISP: see *Addendum to the 2023 Inputs, Assumptions and Scenario Report* at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

- **Australia's** commitment to reaching net zero emissions by 2050 has been in place since 2015. The Federal Government increased the interim 2030 reduction to 43% (from 2005 levels), supported by an 82% renewable energy target under the Powering Australia Plan and the Rewiring the Nation policy, with the recent Capacity Investment Scheme expansion and Renewable Energy Transformation Agreements supporting those targets.
- **The Australian Capital Territory** achieved its target to source 100% renewable electricity from renewable generators in 2020, and has emissions reduction targets of 50-60% reduction by 2025 (from 1990 levels), 65-75% by 2030, 90-95% by 2040 and net zero by 2045.
- **New South Wales'** emissions reduction targets of 50% by 2030 and net zero by 2050 are supported by the Electricity Infrastructure Roadmap. The roadmap legislation requires the equivalent annual generation of at least 12 GW of new renewable generation, and at least 2 GW / 16 GWh of long-duration storage by 2030, beyond 2019 levels.
- **Queensland** has expanded its renewable energy targets to 50% by 2030, 70% by 2032, and 80% by 2035. The Queensland Energy and Jobs Plan and SuperGrid Blueprint call for transmission and two large-scale pumped hydros for firming: Borumba Dam Pumped Hydro and Pioneer-Burdekin Pumped Hydro.
- **South Australia** has emissions targets of 50% reduction (from 2005 levels) by 2030 and net zero by 2050. The Hydrogen Jobs Plan includes a 250 megawatts (MW) electrolyser and a 200 MW hydrogen-capable generator, with budget commitments and supporting legislation in place.
- **Tasmania's** renewable targets of 150% of 2020 generation levels by 2030 and 200% by 2040 were set in 2020. In support, the Tasmanian Government is exploring the new hydro Battery of the Nation project.
- **Victoria's** near-term emissions reduction targets of 28-33% by 2025 (from 2005 levels) and 50% by 2030 were set in 2017. In May 2023, a new target of 75-80% by 2035 was set and the net zero target was brought forward to 2045. These targets are now supported by transmission, renewable generationand storage targets, and Offshore Wind Targets of 2 GW by 2032, 4 GW by 2035 and 9 GW by 2040.

Network upgrades are underway

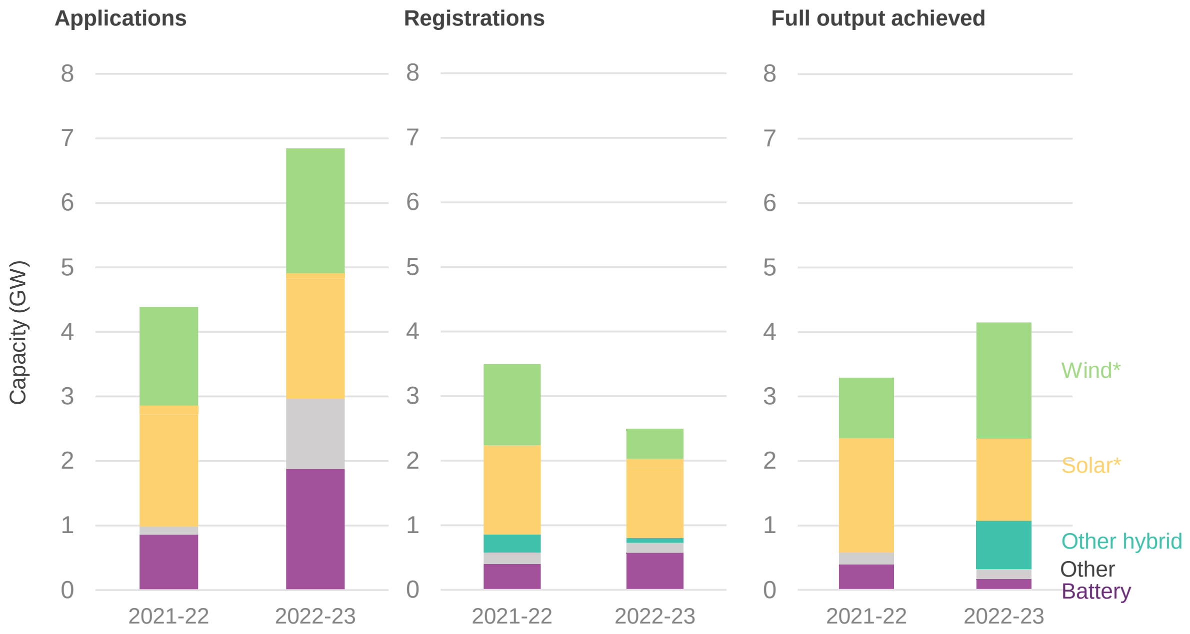
Network capacity was increased between Queensland, New South Wales and Victoria in 2023, and upgrades are also underway within regions, with the Eyre Peninsula expansion completed in 2023 and a reinforcement in far North Queensland nearing completion. Several capacity increases are well under way in committed and anticipated projects, with Project EnergyConnect on track to further connect South Australia with its eastern neighbours.

Heavy investment in utility-scale renewables

Developers have delivered a comprehensive portfolio of generation and storage projects, with a strong pipeline seeking connection to the NEM and achieving critical milestones on the way towards becoming operational (see Figure 10 below):

- 6.9 GW of generation and storage connection applications were approved in 2022-23, with GPG being 15%, and wind, solar and batteries about a third each of the remainder.
- 2.5 GW of generation and storage registrations were approved in 2022-23. Solar accounted for 40% of new plant registered in 2022-23, with both wind and battery accounting for 20% each. Of the 12 GW of projects in pre-registration phase, 6.8 GW of new generation have signed a connection agreement with the local network service provider and are ready for construction. This could increase the number of projects registering to the NEM in the coming years.
- 4.1 GW of generation and storage projects achieved full output in 2022-23. About 43% were wind, 30% solar, 20% both wind and solar, with the remainder being batteries and GPG.

Figure 10 Connection milestones, NEM (GW, 2021-22 and 2022-23)



Note: Wind and Solar include a small number of connections with a battery included in the connection.

2.3 But there are inherent tensions

For this transition to succeed, four tensions must be managed that have always existed, but which are becoming more and more apparent. The way these tensions are managed will determine how quickly and how harmoniously the energy transition happens.

Today and tomorrow

For the transition to succeed, lights must be kept on and the gas flowing while the new system is put in place. This is a highly complex technical challenge, but also a social and economic one.

Coal generators are retiring earlier than initially announced, and a 'just in time' transition to replacement infrastructure would risk reliable supply. The need for renewable energy, transmission, storage and backup gas generation is critical now and throughout the transition. The critical thing is timing, to make sure the new generation and firming capacity comes in ahead of coal retirements.

Yet rushing the transition is also risky. Market rules need to be in place and well understood, so that timely investments can be made. Global supply chains need to be negotiated so that equipment is available to deliver the transition at reasonable cost. Policies need to ensure that Australia has a skilled workforce to draw on as the transition ramps up. Communities must be engaged so that social licence for these rules and investments is earned. These issues take time to resolve well.

Parts and the whole

The second tension is about integrating the diverse range of technologies, small and large, that a multi-gigawatt clean energy system needs.

The first aspect of this tension is in connecting generation or storage assets to the whole system. Australia's processes to register, connect and commission new resources are highly regarded by overseas operators, and the times needed are shortening, but AEMO acknowledges that these processes need to be further streamlined.

Another aspect is the shift from coal to renewables. Coal generators have been the 'electrical heartbeat' of the power system since the NEM was formed. AEMO and other planning bodies are fast learning what innovations and standards are needed for a power system to run on high levels of renewables. This includes learning from and sharing with system operators and research institutions around the globe.

People and populations

The third tension is about the social licence needed to deliver secure and affordable electricity for all. Again, the tension lies in two places.

The first is where communities are asked to host infrastructure for Australia's energy future, and share the benefits with new industries across regional Australia and with households and businesses in our cities. While most Australian communities in city, regional and rural settings have long lived with electricity generation, transmission and distribution, communities facing them for the first time have legitimate questions and concerns.

Building social licence with communities is a real world, steady dialogue with communities to build understanding and trust, through sound processes, listening and responding. It takes into account the intrinsic commitments that communities have to and with each other (for example, the right for farmers to farm, rural communities to function harmoniously, and Aboriginal and Torres Strait Islander people to practice culture). Community acceptance of projects is fostered when organisations prioritise trust, and deliver promised benefits.

The second place where 'people and populations' meet is where households, businesses and communities have invested in their own energy resources. At times, rooftop solar offers so much electricity to the grid that action is needed to ensure power system security. However, if owners allow some coordination of their assets, including batteries and EVs, it will help keep them and the power system as a whole in balance. With the right incentives and systems, these assets can reduce the need for utility-scale investments, and materially reduce the cost of the energy transition.

Australia and the world

Australia is not the only country transforming its energy system, with the whole world competing for the same investment, equipment and engineering skills. Private investment is being attracted by public incentives: governments have allocated US$1.34 trillion to clean energy investments since 2020, and US$130 billion in the six months to June 2023[7].

This stimulus is led by the United States, where the *Inflation Reduction Act* is estimated to invest at least US$370 billion to attract private investment in renewable technology and manufacturing over a decade[8]. Japan's *Green Development Strategy* is intended to stimulate US$100 billion in private investment over 10 years[9], while South Korea's *New Deal* allocated US$60 billion to the energy transition[10]. Similarly, the European Union's *Green Deal Industrial Plan 2022* is supporting EU-located green technology, critical mineral supply and energy-efficient semiconductor chips, and Canada's *Budget 2023* allocates US$58 billion to clean energy[11]. To all of which must be added investment by China and India.

The enormous demand for green technologies will continue to influence costs, stretch and grow supply chains, and test delivery schedules. Managing these tensions will take the industry's collective strategic planning, and the disciplines to carry those plans through.

[7] International Energy Agency. 'Governments are continuing to push investment into clean energy amid the global energy crisis', June 2023, at https://www.iea.org/news/governments-are-continuing-to-push-investment-into-clean-energy-amid-the-global-energy-crisis.

[8] International Energy Agency. 'Inflation Reduction Act of 2022', April 2023, at https://www.iea.org/policies/16156-inflation-reduction-act-of-2022.

[9] Japanese Ministry of Economy, Trade, and Industry. *Overview of Japan's Green Growth Strategy Through Achieving Carbon Neutrality in 2050 (Provisional translation),* March 2021. At https://www.mofa.go.jp/files/100153688.pdf.

[10] International Energy Agency. 'Korean New Deal', July 2021. At https://www.iea.org/policies/11514-korean-new-deal-digital-new-deal-green-new-deal-and-stronger-safety-net.

[11] Government of Canada. *Budget 2023: Chapter 3.* At https://www.budget.canada.ca/2023/report-rapport/chap3-en.html#a7.

3 Planning our electricity future

The ISP is an essential part of AEMO's work in managing the tensions inherent in the energy transition, and in adding to confidence for the investment needed.

It is a plan "*for the efficient development of the 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*"[12], taking relevant government energy policies into account.

In simpler terms, the ISP is a plan for secure, reliable and affordable power, and AEMO extends the horizon to 2050 to recognise Australia's net zero emissions target.

To develop the ISP, AEMO creates 'development paths' – combinations of the transmission, generation, storage and firming investments needed under different future scenarios. It analyses the costs and benefits of these paths using a framework set by the Australian Energy Regulator, and chooses a plan that best delivers secure, reliable and affordable electricity as the 'optimal development path'.

The ISP is the most comprehensive and robust analysis of the NEM's future power system needs. It is rigorously prepared in collaboration with NEM jurisdictional planners and policy-makers, energy consumers, asset owners and operators, and market bodies, with this Draft ISP open to public comment before being finalised in June 2024.

This section sets out how the ISP:

3.1 Considers the whole NEM power system,

3.2 Prioritises reliable, secure and affordable electricity while meeting policy commitments, and

3.3 Is rigorously developed in consultation with the entire energy industry.

3.1 A plan that considers the whole NEM power system

The ISP is a roadmap for the transition of the NEM power system, with a clear plan for both new and existing technologies.

However, the NEM power system is not an isolated engineering system. It must operate in the real economy, responding to government policies, infrastructure costs, workforce availability and community responses to the energy transition.

In particular, the ISP considers:

- government energy and environmental policies, including emission reduction and renewable energy targets, and policies for REZs and electricity infrastructure[13],

[12] National Electricity Rules (NER) 5.22.2.

[13] NER 5.22.3(b) provides requirements for public policies' inclusion in the ISP. In November 2023 a new emissions reduction element came into force in the National Electricity Objective (NEO) of the National Electricity Law. AEMO has chosen to apply the amended NEO in its preparation of the Draft 2024 ISP, by using only scenarios that comply with Australian governments' emissions reduction policies and by considering policies and targets in the Australian Energy Market Commission's *Emissions Targets Statement,* including those which are on their way to meeting (but have not yet met) the National Electricity Rules requirements for public policies' inclusion in the ISP.

- future trends in electricity consumption, net of CER, energy efficiency savings, and the electrification of transport, heating, cooling and cooking,
- future trends and costs in existing and new transmission, generation and storage technologies, including the design and implementation of new REZs,
- power system reliability and security needs[14] that must be met as new technologies are integrated, and
- the interaction of the power system with other 'coupled' sectors such as transport, gas and hydrogen.

3.2 The reliability, security, affordability and emissions reduction needs

The objectives of the ISP align with the National Electricity Objectives, which are to promote efficient electricity services for the long-term interests of consumers. This takes in three sets of considerations: reliability and security, price and quality (affordability), and the need to reduce Australia's greenhouse gas emissions. These three objectives are discussed below, and balancing reliability and affordability is a matter of judgment.

Reliability and security as 'power system needs'

The NEM power system needs to be reliable and secure, operating within engineering limits and operating standards[15], as shown in Table 2.

Table 2 Power system needs considered in the ISP

Need	Operational requirements considered when developing the ISP	
Reliability	**Resource adequacy and capability**	Continuous real-time balancing of supply and demand. In addition, energy resources provide sufficient supply to match demand from consumers at least 99.998% of the time under the NEM Reliability Standard.
		Reserves exist to provide 'a buffer' – available to assist in meeting electricity demand in challenging conditions.
		Network capability is sufficient to transport energy to consumers.
Security	**Frequency and inertia**	Frequency control, minimum and secure levels of system inertia, and transient and oscillatory stability are maintained within operating and planning standards.
	Voltage management and system strength	Voltage control and fault levels are maintained within operating and planning standards and below equipment ratings.
	System restoration and flexibility	The right mix of flexible resources are available to maintain and restore the supply-demand balance across different timescales.

To be reliable, the NEM must match supply with demand from consumers while keeping power system equipment within its operating requirements. In addition, the NEM must be operated over the year so that there is enough supply to make sure that demand is met at least 99.998% of the

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

[15] NER 5.22.3(a), with the details set out in the NER for the reliability standard (3.9.3C(a)); system security principles (4.2.6), system standards (Schedules 5.1 and 5.1a), and applicable regulatory instruments (defined in NER Chapter 10).

time. To meet both of these needs, reserves may be required to respond to demand peaks during periods of extreme heat or cold or to cover potentially long periods of dark and still 'renewable droughts' across the NEM, as well as flexible generation that can respond to regular large swings in demand.

To be secure, the system must continue to operate within defined technical limits, despite highly variable demand and renewable supply, even if a major power system element (such as a generator or interconnector) is unexpectedly disconnected. If such an element fails, the system must be returned to secure operations as soon as practical, within 30 minutes.

Appendix 4 System Operability and Appendix 7 System Security discuss most completely how system reliability and security are being provided through to 2050, though the issues are touched on throughout the ISP.

Affordability as 'long-term interests and net market benefits'

'Affordability' is considered in the ISP's purpose to serve 'the long-term interests of electricity consumers', taking into account the 'price, quality, safety, reliability and security' of supply[16]. This is measured by the 'net market benefits' that a development path may bring, which are in turn driven by 'low long-term system costs'. The lower those long-term costs are, all else being equal in an efficient market, the lower energy prices will be.

The benefits and costs considered in the ISP are set out in the 2023 ISP Methodology and captured in Table 3 below. Unless otherwise indicated, these benefits are assessed for all utility-scale generation, firming and transmission infrastructure in the NEM.

AEMO notes, however, that lowering long-term system costs generally means investing in new assets, generally up front. That means short-term affordability is only protected if investments are repaid over long-term schedules that do not penalise current consumers. The ISP assumes that these payment schedules are adopted by investors, and reflected in wholesale energy markets.

Table 3 Classes of market benefits considered in the ISP cost-benefit analysis

Benefit	Realised by	Identified by
Operational costs	Low operating costs	Calculating plant maintenance, plant start-up and other operating costs.
	Reduced fuel costs	Co-optimising future generation, storage, and transmission build (and retirement) timings and calculating the fuel costs associated with this generation mix and future dispatch patterns.
	Reduced operational curtailment	Calculating the value to the customer of either voluntary curtailment or involuntary load shedding.
	Reduced network losses	Assessing additional generation costs effectively wasted due to network losses under each alternate development path across interconnectors.
Capital cost	Efficient investment timing	Investments being delivered in time for when they are needed, and deferred if they are not yet required.
	Optimal investment size	Total generation, storage, and transmission costs, compared to the case of no new transmission.

Note: AEMO does not consider ancillary service costs or competition benefits as part of the cost benefit analysis for the ISP because they are not generally material compared to other projects costs, as set out in the *2023 ISP Methodology*. Where material, changes in ancillary service costs may be considered by transmission network service providers (TNSPs) as part of subsequent RIT-T analysis on any actionable projects.

[16] A consideration in the National Electricity Objective: National Electricity Law (NEL) s 7(a).

Balancing affordability and reliability

The ISP is a plan to optimise investment, considering various futures and risks, in a way that achieves system security and reliability at the least long-term cost.

In preparing the ISP, AEMO may apply its professional judgement to reflect consumers' risk preferences[17]. Consumers may seek lower costs, but not at any level of risk. A major challenge for planners is to balance the risks of investment that is 'too early' or 'too late' in an uncertain future. Too early may mean over-investing in things that in the end are not needed. Too late, after waiting for certainty, may mean the system is less able to maintain reliable, secure and affordable power if unpredictable events occur.

In 2023, AEMO surveyed and met in person with residential consumers across the NEM, seeking to understand consumer risk preferences on infrastructure investment. The research suggests that these consumers generally prefer some level of early investment if it will reduce the risk of later volatility in their bills, so long as it is not too much. However, some consumers were willing to pay more, and some were not willing or able to pay anything additional now.

Further details see: Summary of consumer risk preferences project.

Emissions reduction as an element in the National Electricity Objective

A recent addition of an emissions reduction element to the National Electricity Objective (NEO) in Australia's electricity law requires that AEMO plan the power system in a way that helps governments achieve targets that reduce greenhouse gas emissions, as well as being secure, reliable and cost-effective.

AEMO has applied the amended NEO in its preparation of the Draft 2024 ISP as follows:

- Only scenarios that comply with Australian governments' emissions reduction policies have been applied (which meant removing the previous *Slow Change* scenario).
- Policies and targets included in the Australian Energy Market Commission's *Emissions Targets Statement* have been incorporated, including those which are on their way to meeting (but have not yet met) the National Electricity Rules requirements for public policies' inclusion in the ISP. Examples of polices and targets which are on their way to meeting rules requirements are Victoria's offshore wind targets, the Victorian Energy Storage Target, and New South Wales' updated emission reduction targets.
- AEMO may also include a value of emissions reduction in future analysis, potentially for the final 2024 ISP, once a value is determined by an appropriate market institution or government body.

For further information, see *Addendum to the 2023 Inputs Assumptions and Scenarios Report*.

[17] Consistent with the AER's Cost Benefit Analysis Guidelines at https://www.aer.gov.au/industry/registers/resources/guidelines/guidelines-make-integrated-system-plan-actionable and AEMO's *ISP Methodology* at https://aemo.com.au/en/consultations/current-and-closed-consultations/consultation-on-updates-to-the-isp-methodology.

3.3 Preparing the ISP

AEMO develops the ISP every two years, through an inclusive industry collaboration that commences as soon as the last ISP is completed. The Draft 2024 ISP has considered over 1,000 potential development paths, and modelled their performance across three future scenarios. To do so, it has integrated Australia's most comprehensive set of power system models to plan for the optimal development path: an integrated system plan.

A two-year, inclusive engagement process

This Draft ISP is a milestone on an industry-wide journey that started in July 2022 and will only finish when the final ISP is published by 28 June 2024.

Over that time AEMO has engaged and will continue to engage openly with consumer and community representatives, governments, energy market authorities, investors and developers, network planners, industry bodies and science and technology institutions. This includes regular engagement with the ISP Consumer Panel, and seeking input on consideration of social licence from AEMO's Advisory Council on Social Licence. In particular:

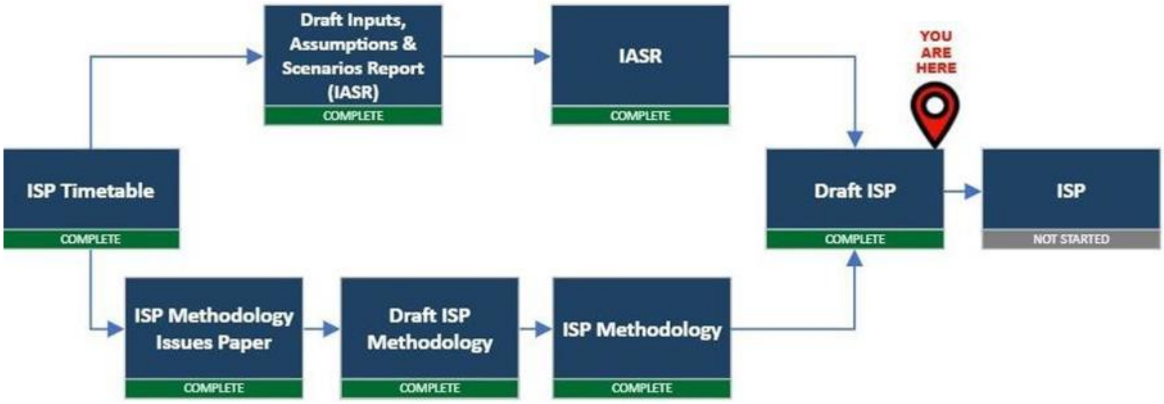
- The ISP considers the forecasts and insights provided in the 2023 *Electricity Statement of Opportunities* and the 2023 *Gas Statement of Opportunities*[18].
- Inputs have been progressively published in the draft and final 2023 *Inputs, Assumptions and Scenarios Report* (the IASR, with an addendum after the Australian Energy Regulator's review), and the draft and final 2023 *Transmission and Expansion Options Report*.
- The methodology for determining the ISP's optimal development path is governed by the National Electricity Rules and the Regulator's *Cost Benefit Analysis Guidelines*, and follows steps set out in the *2023 ISP Methodology.*

In formal consultations, AEMO has published 43 reports, hosted 1,418 attendances across 10 webinars and considered 117 written submissions, and will continue this effort through formal consultation on this Draft 2024 ISP, which will inform development of the final 2024 ISP.

AEMO considers that the development path most likely to succeed is the one which has been transparently and comprehensively tested by as many energy and community experts as possible. While more can always be done, AEMO is confident that this Draft 2024 ISP represents the best effort possible by the energy sector and its stakeholders to set out a clear and actionable plan for our energy future.

[18] The ISP must have regard to these reports: NER 5.22.10(b).

Figure 11 ISP consultations

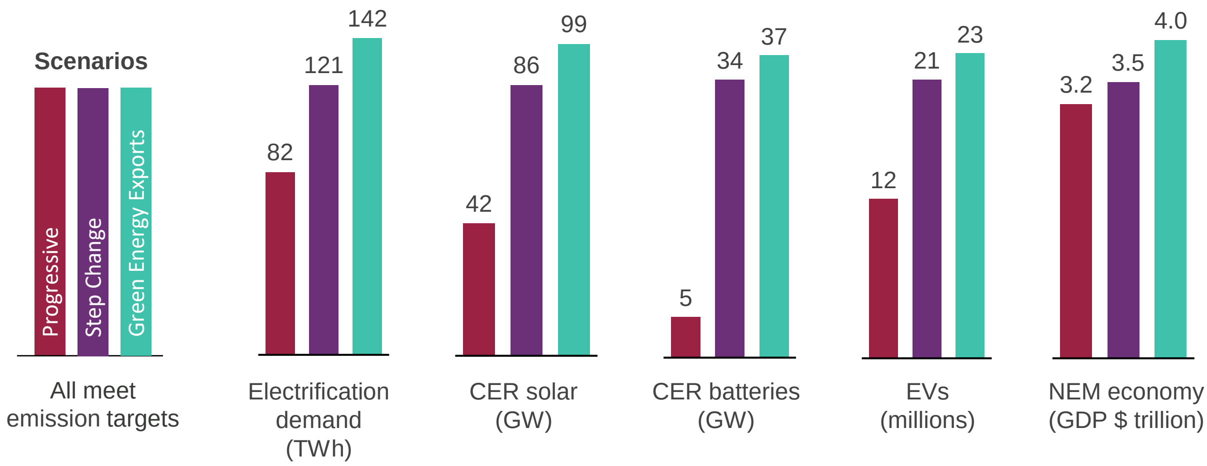


Three potential scenarios for the future

Through industry consultation, AEMO considered and published three scenarios in the 2023 IASR*:* see Figure 12. Each acknowledges the retirement of coal-fired generation through the 2030s and aligns with government policy commitments:

- ***Step Change*** reflects a pace of energy transition that supports Australia's contribution to limit global temperature rise to less than 2°C, with consumer energy resources (CER) contributing strongly to the transition.
- ***Progressive Change*** also reflects Australia's current policies and commitments to decarbonisation, but more challenging economic conditions and supply chain constraints mean slower investment in utility-scale assets and CER.
- ***Green Energy Exports*** reflects a very rapid decarbonisation rate to support Australia's contribution to limit global temperature rise to 1.5°C, including strong electrification and a strong green energy export economy.

Figure 12 Three scenarios of the future for ISP modelling



The choice of the ODP depends in part on the relative likelihood of these scenarios. To help determine the likelihoods, AEMO considered the insights of a 'Delphi Panel' of more than 30 participants, including industry experts, government representatives, network service provider representatives, generators and retailers, researchers, academics, and consumer advocates. The *Step Change* scenario received the most consistent level of support and was considered the most likely scenario by most participant groups. Support for *Progressive Change* was also relatively high, yet it was also more polarised, with more diversity of views between participant groups.

Considering the Delphi Panel insights, AEMO has assigned likelihoods of 43% for *Step Change*, 42% for *Progressive Change* and 15% for *Green Energy Exports*. The *Step Change* scenario is AEMO's 'most likely' scenario for this Draft 2024 ISP, although the near-term transition is very similar in *Progressive Change*.

Integrated modelling to identify the ODP

The methodology for determining the ODP is set at a high level in the National Electricity Rules and provided in detail in AEMO's *ISP Methodology*[19].

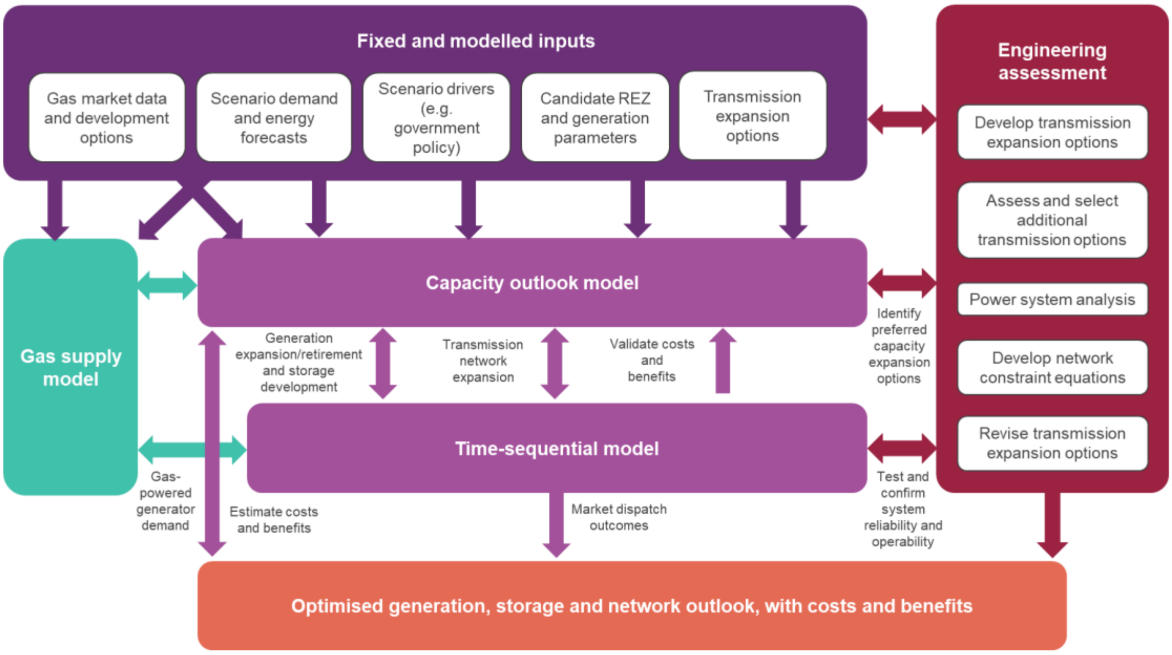
AEMO relies on a suite of models and analyses that covers generation and storage investments, as well as transmission projects. The components of this suite is shown in Figure 13 (over page):

- The **fixed and modelled inputs** are published in the *Inputs, Assumptions and Scenarios Report*, and are influenced by **engineering assessments** of the NEM's capabilities.
- The **capacity outlook model** uses these inputs to develop options for generation, transmission and dispatch, in each of the ISP scenarios, aiming to minimise capital and operational costs over the long-term while achieving the ISP's objectives.
- The **time-sequential model** then optimises electricity dispatch for every hourly or half-hourly interval. It validates the outcomes of the capacity outlook model, and feeds information back into it.
- The **engineering assessment** tests these outcomes against the power system requirements (security, strength, inertia) and assesses marginal loss factors to inform new grid connections. These assessments feed back into the two models to continually refine outcomes.
- The **gas supply model** is used to test whether gas pipeline and field developments will meet the operational needs of gas generation.
- Finally, the **cost-benefit analyses** identify the net market benefits and potential 'regret' costs of each candidate development path, in each scenario, against each sensitivity analysis.

AEMO then applies its professional judgement to these outcomes to finalise the ODP.

[19] At https://aemo.com.au/en/consultations/current-and-closed-consultations/consultation-on-updates-to-the-isp-methodology.

Figure 13 ISP modelling methodology



PART B

An optimal development path for reliability and affordability

Part B:
An optimal development path for reliability and affordability

Renewable energy connected by transmission, firmed with storage and backed up by gas-fired generation is the lowest cost way to supply electricity to homes and businesses throughout Australia's transition to a net zero economy.

In consultation with stakeholders, AEMO has comprehensively considered each of the consumer needs, government policies, potential issues and scenarios introduced in Part A.

The optimal size, place and timing for the NEM's future generation, firming and transmission form the ISP's optimal development path (ODP). The ODP aims to deliver reliable and affordable power to meet NEM needs for at least 20 years, fulfil the NEM's security and reliability requirements, meet government policy settings and manage risk through a complex transformation.

Part B details how the NEM is forecast to develop in the *Step Change* scenario.

- **Section 4 – Renewable generation, focused in REZs.** The total capacity of utility-scale wind and solar increases seven-fold by 2050 – from 19 GW currently to 126 GW in Step Change – a doubling every decade. In addition, the capacity of rooftop solar and other distributed solar rises from 19 GW to 86 GW.
- **Section 5 – Network investments in the ODP.** Transmission projects consistent with previous ISPs or as announced by a state government, including two projects that are made actionable for the first time in this ISP.
- **Section 6 – Storage and services to support renewable generation.** 74 GW of firm dispatchable capacity is needed by 2050, as well as additional power system security services.
- **Section 7 – Rationale of the ODP**. The ODP and its benefits have been determined as required by the National Electricity Rules, following the *ISP Methodology.*

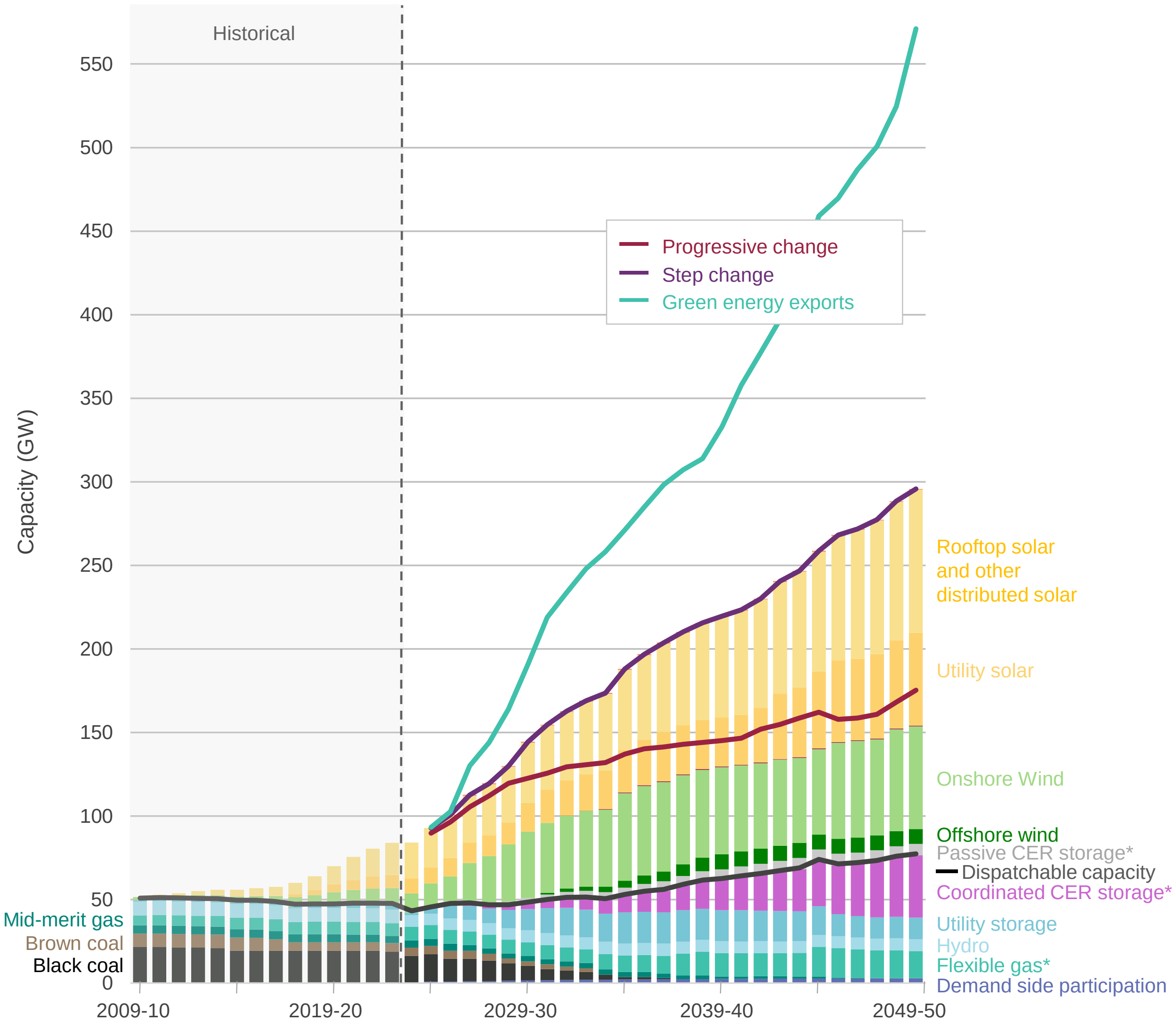
The ISP projects the optimal mix of generation and storage, including renewables such as solar and wind as well as firm capacity technologies like battery storage, pumped hydro and gas-fired generation. AEMO projects this mix based on capital and operating costs from GenCost, rather than using a levelised cost of electricity (LCOE) which is used by industry as a high-level guide.

The transmission projects in the ODP allow efficient investment in generation and storage, and add resilience. Their annualised cost through to 2050 is estimated to total $16.4 billion[20] and, after paying themselves back, they would avoid $17 billion in additional costs to consumers.

Changing one element of the ODP is likely to render other elements, and the whole, less effective and more expensive. AEMO has also considered alternative solutions to the NEM's requirements.

[20] This value does not include the cost of commissioned, committed or anticipated projects.

Figure 14 Capacity, NEM (GW, 2009-10 to 2049-50)



Note: Flexible gas includes gas-powered generation as well as potential hydrogen and biomass capacity.
"CER storage" are consumer energy resources such as batteries and electric vehicles.

4 Transition to renewable generation

Renewable energy connected by transmission, firmed with storage and backed up by gas is the lowest cost way to supply electricity to homes and businesses throughout Australia's transition to a net zero economy.

The NEM's transformation is well underway, promising material benefits but grappling with inherent tensions. Investment in both utility-scale and consumer-owned renewable generation is needed to meet growing demand for electricity as coal generation retires.

This section sets out how:

4.1 Coal is retiring, faster than announced.

4.2 Rooftop solar and other consumer-owned energy resources are forecast to grow four-fold.

4.3 Utility-scale solar and wind are forecast to grow seven-fold.

4.4 REZs are being planned to house most of the utility-scale assets.

4.1 Coal is retiring, faster than announced

As discussed in Section 1.1, ten coal-fired generators have retired over the last decade. Owners of all but one plant of the remaining fleet have announced retirements between now and 2051, with about half announcing retirements by 2035. This would continue the steady rate of retirement since the peak of installed capacity in 2012.

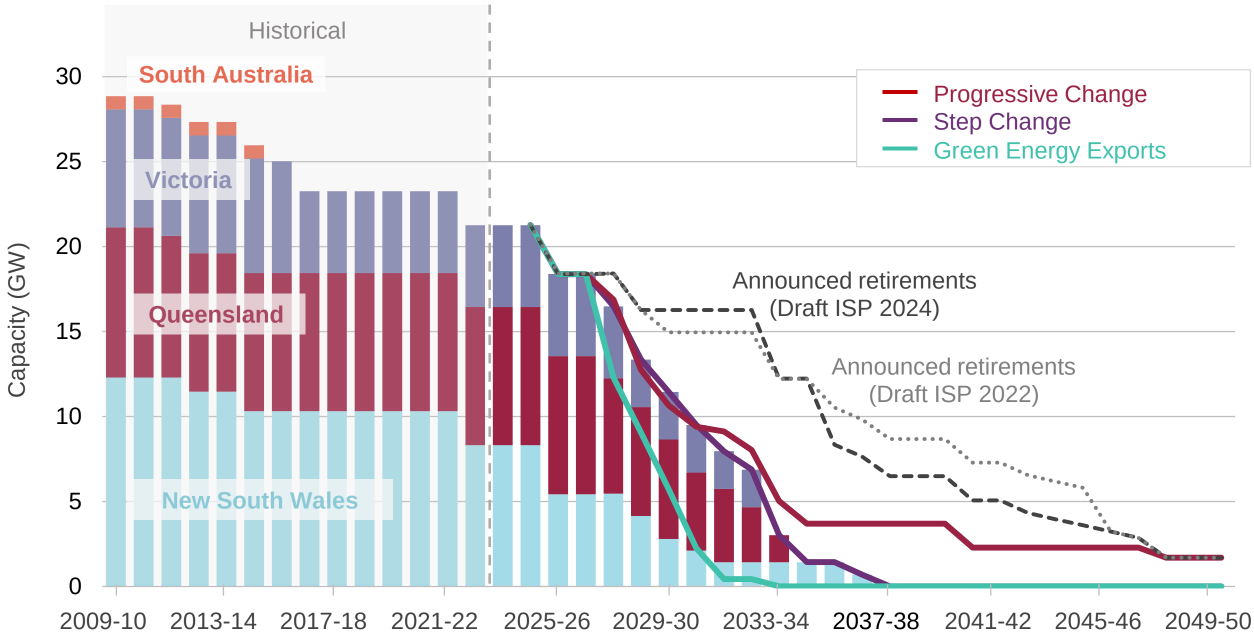
The ISP forecasts suggest that the remaining coal fleet will close two to three times faster than those announcements. About 90% of the NEM's coal fleet is forecast to retire by 2034-35, with all coal generators retired by 2037-38 in the *Step Change* scenario: see Figure 15 (over page).

However, coal retirements may occur earlier than even this forecast, as they have in the past. Ownership has become less attractive, with higher operating costs, reduced fuel security, and high maintenance costs as well as increasing competition by lower-cost renewable energy in the wholesale market.

Coal owners are only required to give three-and-a-half years' notice of a closure, which is very little time in which the NEM has to respond. Given the lead time to deliver new assets, replacement capacity must be put in place well in advance.

Government policies and corporate strategies are driving the needed changes. The ISP informs how those investments can be made efficiently to maintain a reliable and secure power system.

Figure 15 Coal capacity, NEM (GW, 2009-10 to 2049-50)



4.2 Four times today's consumer energy resources

Many consumers are taking more direct responsibility for their energy needs, particularly as they rely more and more on electricity. Increasingly, they are investing in solar systems, batteries,EVs, and other energy management solutions. Virtual power plants (VPPs) are starting to aggregate those assets into larger systems, trading energy between them and the grid, and maximising the system benefits that these resources can provide.

- **Solar generation continues to rise.** Today, one-third of detached homes in the NEM have rooftop solar. By 2034 in the *Step Change* scenario, over half of the detached homes in the NEM would do so, rising to 79% in 2050, driven by ever-falling costs. At that time, forecast total rooftop solar capacity is 72 GW.
- **Residential and commercial batteries** are becoming more numerous as costs decline, with adoption forecast to grow strongly in the late 2020s and early 2030s. The *Step Change* scenario forecasts growth in capacity from today's 1 GW to an estimated 7 GW in 2029-30, and then 34 GW in 2049-50.
- **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 63% (*Progressive Change*) and 97% (*Step Change*) of all vehicles are expected to be battery EVs.

When rooftop solar growth is combined with growth in PV non-scheduled generation (PVNSG), total solar generation grows by four times between today and 2050.

Any growth in CER reduces the need for utility-scale solutions, especially if the assets can be coordinated or 'orchestrated' to complement and support the grid most efficiently. An increasing proportion of rooftop solar, EVs, household and community batteries and even household hot water and pool pumps are expected to have the 'smarts' to help manage the import and export of electricity to the distribution grid. How this works will depend on a mix of financial incentives, technology and communication standards, customer preferences, and market or policy arrangements. This will require increased engagement between consumers, retailers, networks and other market participants: see Section 8.2.

The potential of coordinated CER is demonstrated by Project EDGE[21], a recent industry pilot in which households and businesses engaged directly or through aggregators with the wholesale electricity market. With clear information and market incentives, the project delivered financial benefits to all participating parties.

4.3 Seven times today's utility-scale wind and solar

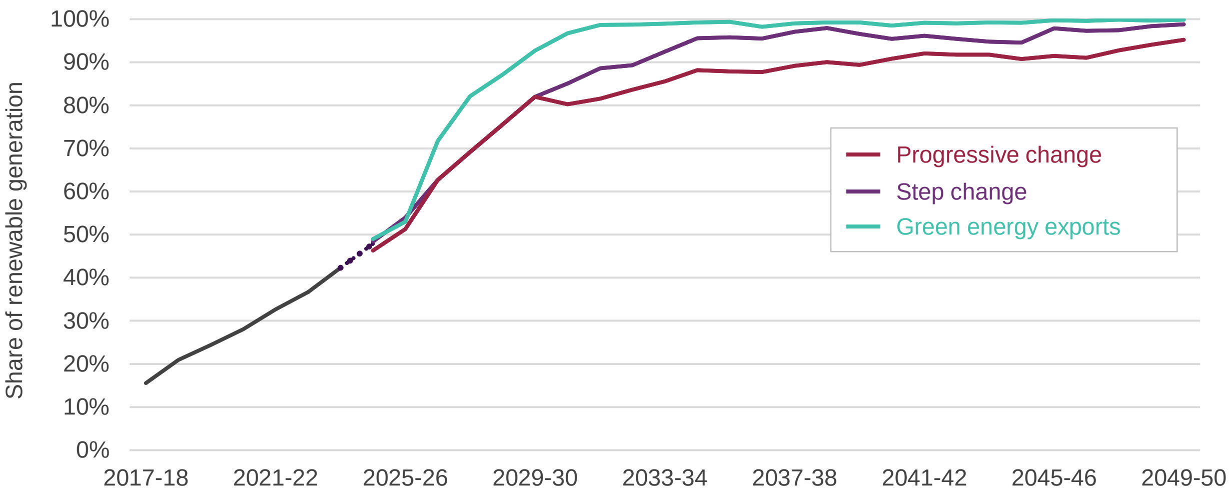
With most coal forecast to withdraw by 2034-35, the race is on for new utility-scale generation both to replace that coal capacity and then provide for tomorrow's industry and transport.

As a share of annual generation, renewable energy including hydro and biomass reached 32% in 2021-22. In *Step Change*, this is forecast to reach almost 70% in 2027-28, 82% in 2029-30, and 99% by 2049-50: see Figure 16.

By 2034-35, the NEM is forecast to need approximately 82 GW of utility-scale wind and solar, and 126 GW by 2049-50. This would be seven times the current NEM capacity of 19 GW, with another 5 GW committed or anticipated to be operational before the end of 2024.

This means that the current rate of investment in renewables has to accelerate. In *Step Change* around 6 GW of new capacity is needed each year until 2029-30, easing back to over 3 GW per year through the 2030s. *Progressive Change* also calls for around 4 GW each year this decade, before easing to under 2 GW per year next decade.

Figure 16 Share of generation from renewable sources, NEM (2017-18 to 2049-50)



21 Project EDGE (Energy Demand and Generation Exchange) https://arena.gov.au/assets/2023/10/AEMO-Project-EDGE-Final-Report.pdf.

Mix and spread of renewable generation

Renewable energy technologies complement each other, and transmission allows the NEM to take advantage of different weather conditions across eastern Australia. While conditions may be 'dark and still' in some places, it is highly unlikely to be so everywhere, so fewer grid-scale generation and storage assets are needed for secure and reliable supply across the NEM: see Section 6.5.

Early investment favours wind, with utility-scale solar catching up to a 40% share by 2050. Wind and solar are broadly complementary: wind generates energy overnight when solar cannot, and is typically stronger in the winter months. With strong rooftop solar in place, wind is forecast to account for 77% of new utility-scale variable generation through to 2030.

Offshore wind can drive further diversity in the generation mix. Offshore wind turbines may also contribute to Australia's energy mix. They capture stronger, more consistent wind than onshore turbines. However, onshore wind is lower cost, assuming it can be sited appropriately and connected efficiently to the grid. If not, and with policy support, offshore wind may be attractive.

Spilling or curtailing surplus renewable generation

As seen in Section 6 below, grid demand and consumption are forecast to become higher in winter than in summer. The NEM's generation capacity must be able to meet higher winter demand and ensure the surplus in summer can be stored.

However, building the network, storage and system services to use or store every last watt of energy makes little financial sense. It would be more efficient to curtail generation when there are security constraints in the network, or spill generation when there is over-abundant renewable energy supply.

Approximately 20% of renewable generation is forecast to be spilled or curtailed in 2050. Further market reform is required to ensure incentives are in place for investors to develop an optimal level of capacity.

4.4 Renewable energy zones to efficiently connect renewables

Much of the new renewable generation would be built in REZs now being established in all NEM regions: see Figure 17 below. They are selected for the quality of their renewable resource, and their proximity to consumers and existing transmission.

The REZs are a place-based way to build and coordinate electricity assets, with a more holistic approach to the needs of the energy transition and the aspirations of regional communities.

Efficient clusters of renewable energy development

If well planned and supported by appropriate social licence, REZs can:

- greatly reduce the overall cost and disruption of the energy transition, and deliver significant regional benefits,
- meet the needs of the power system, with better grid reliability and security, and the option to scale up to address the future needs of the power system,

- allow for more coordinated and effective community consultation,
- share the costs of transmission, connection and support infrastructure (such as weather observation stations) across multiple projects,
- promote regional expertise and employment over long periods to build and maintain generation and storage assets and the equipment needed to ensure power system security, and
- reduce the community, environmental and aesthetic impacts of state-wide development.

REZ candidates were initially developed for the 2018 ISP[22], and have been updated, refined and added to through both the ISP and state-based consultation processes: see Appendix 3. State energy infrastructure planners have engaged with relevant communities on both high-level and detailed REZ planning and development. The industry is conscious that these communities weigh both the economic and social benefits and the potential costs and risks of this investment: see Section 8.3.

REZ and network design to optimise capacities

The details for each of the 43 considered REZs in the NEM are set out in Appendix 3. These include an assessment of the REZ's solar and wind resource, forecast generation capacity, transmission implications, climate and event risks, and forecast curtailment and spill levels.

By state, the needs are forecast to be:

- **Tasmania: over 3.7 GW of onshore wind by 2049-50**, with no offshore wind. Project Marinus and the Central Highlands REZ are established from 2029-30 onward.
- **Victoria: 22 GW new utility-scale wind and solar by 2049-50 including 9 GW offshore wind.** Increased network capacity from Victoria – New South Wales Interconnector West (VNI West) and Western Renewables Link (WRL) allows more wind in Western Victoria and solar in Murray River REZs. Offshore wind can access the network capacity vacated by retiring coal generation in the La Trobe Valley, and delays need for network upgrades in Gippsland areas.
- **South Australia: 9 GW new utility-scale wind and solar by 2049-50**. Over 9 GW of new renewables are forecasted for the region by 2050. Expansion of the Mid-North South Australia REZ is needed in the mid-2040s to access mid-north wind and northern solar.
- **New South Wales: 34 GW new utility-scale wind and solar by 2049-50.** Resource diversity will be opened by new networks, with an even mix of wind and solar across the state. Over 14 GW new generation capacity in Central-West Orana, 12 GW in New England, 4 GW in South West New South Wales, and 2.4 GW in Hunter-Central Coast by 2050. No offshore wind is yet forecast for New South Wales.
- **Queensland**. **46 GW new utility-scale wind and solar by 2049-50.** The CopperString 2032 and Queensland SuperGrid upgrades allow new renewables in North Queensland (7.7 GW wind), Isaac (9 GW, mainly solar), Fitzroy (11 GW, mainly solar), Darling Downs (15 GW each of solar and wind). REZs in the south of the state are forecast to make use of existing network capacity as coal retires.

[22] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/isp/2018/integrated-system-plan-2018_final.pdf?la=en&hash=40A09040B912C8DE0298FDF4D2C02C6C.

5 Actionable and other network investments

Renewable energy **connected by transmission**, firmed with storage and backed up by gas is the lowest cost way to supply electricity to homes and businesses throughout Australia's transition to a net zero economy.

Section 4 detailed the renewable resources needed to meet consumer demand efficiently as coal generation retires, at the same time as industry and households switch to electricity from coal, petrol and gas fuels.

New transmission and modernised distribution networks are needed to connect these diverse low-cost resources to homes, businesses and industry in our towns and cities. The transmission network brings electricity where it is needed, when it is needed, and improves the power system's resilience. Modernised distribution networks then deliver that electricity to homes and businesses, and take back any surplus from consumers' own assets.

This section describes the transmission projects in the ODP, covering:

5.1 An overview of the forecast transmission needs for the NEM, including a map and listing of the projects that will deliver those needs.

5.2 Listing of projects already committed or anticipated.

5.3 Details of projects that are identified as actionable in this ISP.

5.4 Potential future projects.

These transmission projects link the grid-scale generation assets to the distribution network, and to the ODP's storage and firming assets set out in Section 6.

This period of increased investment in transmission is the first of its kind in at least 25 years, and brings significant consumer and economic benefits: see Section 7.1. Delivery at this scale depends on earned social licence, a dependable supply chain and a skilled workforce. Not securing any one of these will materially risk the timely delivery of the ODP: see Section 8.3.

Appendix 5 sets out full details of the transmission projects, including their identified need as required by the National Electricity Rules.

5.1 Overview of transmission projects over the forecast period

As with the 2022 ISP, the 2024 Draft ISP forecasts that close to 10,000 km of transmission will be needed by 2050 under the *Step Change* and *Progressive Change* scenarios. About 5,000 km of this transmission delivery is in the next decade, creating about 4,000 km of new transmission corridors and upgrading about 1,000 km of existing lines.

If Australia is to pursue the more transformational *Green Energy Exports*, then over twice as much transmission would be needed, delivered at a much faster pace.

The transmission projects that form part of the ODP are listed in Table 4, and set out visually in Figure 17 below. They are categorised as:

- **Five committed or anticipated projects** that are already underway. These make up about half of around 5,000 km of new transmission to be delivered in the next decade, and proponents advise they will be at full capacity before the end of 2029.
- **Seven actionable projects**, for which work should commence or continue as soon as possible under the ISP framework (actionable ISP projects) or the relevant state approvals framework. These projects will provide the other half of the transmission needed over the next decade, and the proponents have advised they will be at full capacity by the end of 2032.
- **A set of future ISP projects in each state** and to connect Queensland and New South Wales. AEMO may require proponents to undertake preparatory activities to enable more detailed consideration in the next ISP.

The actionable and future ISP projects on the optimal development path are selected by AEMO to meet power system needs and optimise market benefits to the NEM[23]. AEMO considers optimal timings will give greater market certainty and enhanced power system resilience as coal retires, allow time for appropriate community co-design of project implementation, and allow flexibility in the procurement of expertise, materials and equipment. However, the actual delivery dates are in the hands of transmission network service providers (TNSPs).

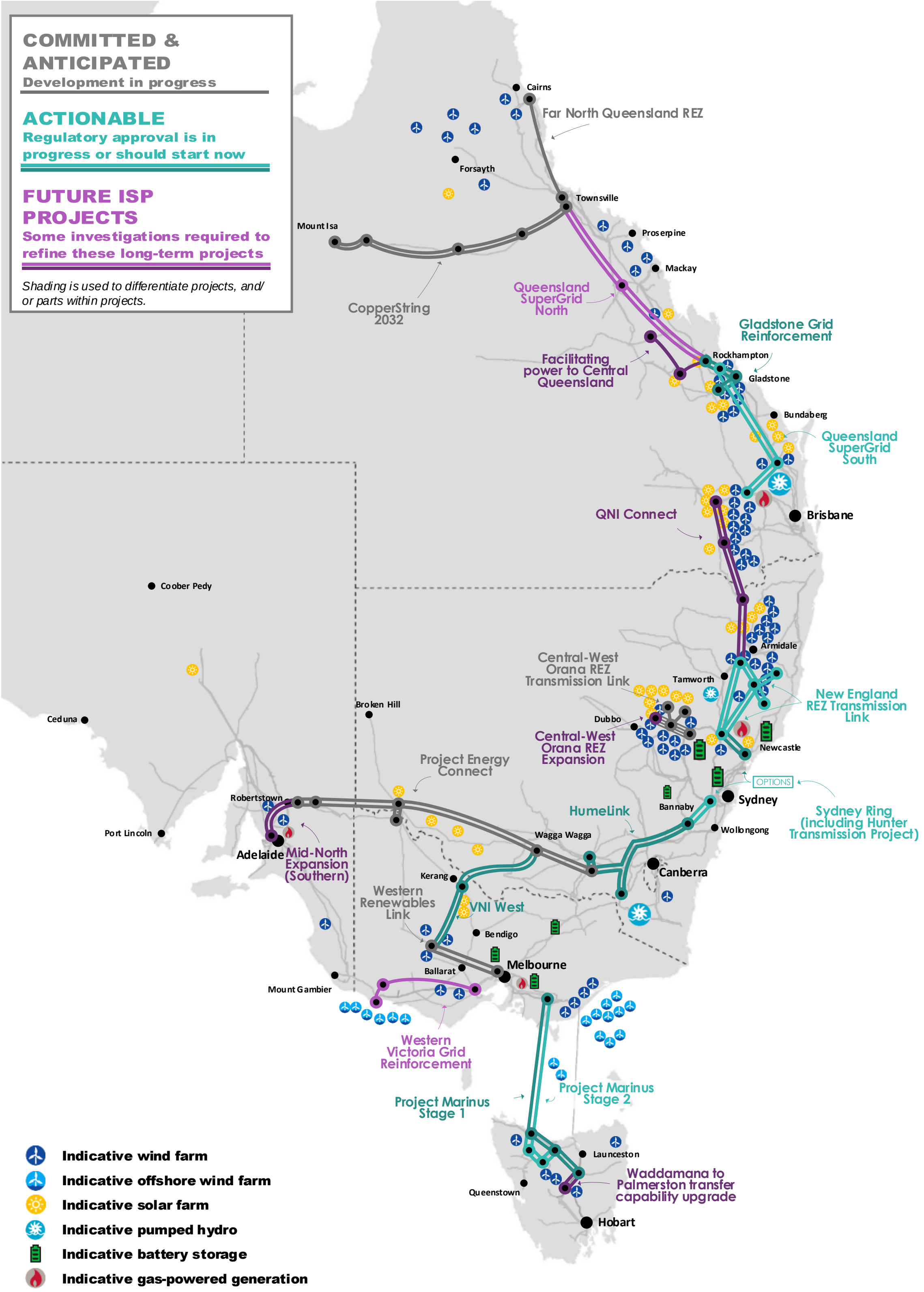
[23] The ISP must specify the identified need for each project (NER r 5.22.6(a)(6)(v)), with credible options able to be implemented in sufficient time to meet the identified need (r 5.15.2(a)).

Table 4 Network projects in the Draft 2024 ISP optimal development path

Committed and anticipated ISP projects		In service timing advised by proponent	Full capacity timing advised by proponent
Far North Queensland REZ		April 2024	April 2024
Project EnergyConnect[A]		Stage 1 April 2024 Stage 2 December 2024	Stage 1 July 2024 Stage 2 July 2026
Western Renewables Link		July 2027	July 2027
Central West Orana REZ Transmission Link		January 2028	August 2028
CopperString 2032[B]		June 2029	June 2029
Already actionable projects ***(confirmed in this Draft ISP)***	**Actionable framework**	**In service timing advised by proponent**	**Full capacity timing advised by proponent**
HumeLink[C]	ISP	Northern Circuit July 2026 Southern Circuit December 2026	Northern Circuit July 2026 Southern Circuit December 2026
Sydney Ring *(Hunter Transmission Project and investigation of southern network options)*	NSW[D]	December 2027	December 2027
New England REZ Transmission Link	NSW[D]	September 2028	September 2028
Victoria – New South Wales Interconnector West (VNI West)	ISP	December 2028	December 2029
Project Marinus[E]	ISP	Stage 1 June 2030 Stage 2 June 2032	Stage 1 December 2030 Stage 2 December 2032
Newly actionable projects ***(as identified in this Draft ISP)***	**Actionable framework**	**In service timing advised by proponent**	**Full capacity timing advised by proponent**
Gladstone Grid Reinforcement[F]	QLD[G]	September 2029	September 2029
Queensland SuperGrid South[F]	QLD[G]	June 2031	June 2031
Future ISP projects			
Interconnectors	Queensland – New South Wales Interconnector (QNI Connect)		
New South Wales	Central West Orana REZ Expansion, Hunter-Central Coast REZ Expansion, Cooma-Monaro REZ Expansion.		
Queensland	Darling Downs REZ Expansion, Facilitating Power to Central Queensland, North Queensland Energy Hub Uplift, Queensland SuperGrid North.		
South Australia	Mid North REZ Expansion.		
Tasmania	Waddamana to Palmerston transfer capability upgrade, North West Tasmania REZ Expansion.		
Victoria	Western Victoria Grid Reinforcement, Eastern Victoria Grid Reinforcement.		

A. The capacity release and timing is conditional on availability of suitable market conditions and good test results.
B. CopperString 2032 will be built and owned by the Queensland Government, continuing the commitment made through the Queensland Energy and Jobs Plan that all the state's transmission assets will be 100% publicly owned. This project was not actioned through the ISP framework.
C. 'Northern Circuit' is between Bannaby and Gugaa. 'Southern Circuit' is between Bannaby and Maragle, and Maragle and Gugaa. Transgrid has advised the Southern Circuit has been programmed to December 2026 for optimal delivery.
D. These are actionable New South Wales projects. They will progress under the *Electricity Infrastructure Investment Act 2020* (NSW) rather than the ISP framework. New England REZ Transmission Link includes additional scope compared to 2022 ISP, with the proponent date only applying to the original scope.
E. Project Marinus includes MarinusLink and North West Transmission Developments (NWTD) projects. Project proponent dates represent modelling dates and are under negotiation. Stage 1 refers to Cable 1 and associated NWTD works, and Stage 2 refers to Cable 2 and associated NWTD works. Project Marinus is a single actionable ISP project without decision rules.
F. Project proponent dates are subject to further refinement.
G. These are actionable Queensland projects. They may progress under the *Energy (Renewable Transformation and Jobs) Bill* 2023 (Qld) rather than the ISP framework.

Figure 17 Transmission projects in the optimal development path



This map shows indicative new generation and storage in 2040, and transmission projects that include new transmission lines, increase capacity by 1,000 MW or more, and are required in all scenarios by 2050.

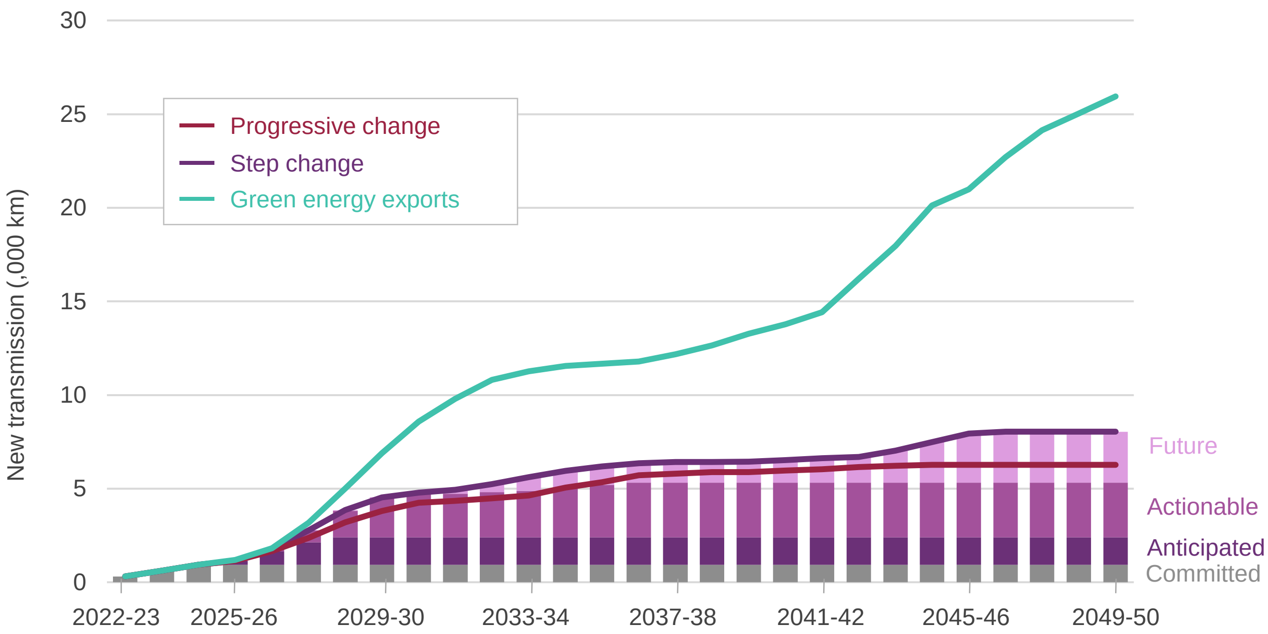
Total transmission, by scenario

The *Step Change* and *Progressive Change* scenarios have similar needs for new transmission until the early 2040s, though delivered marginally slower in *Progressive Change*: see Figure 18.

Both *Step Change* and *Progressive Change* scenarios require around 5,000 km of transmission to be delivered over the next decade, about half of which is already underway as committed or anticipated projects. Around 10,000 km is needed by 2050. After the next decade, more capacity is expected from sources such as CER, storage and offshore wind that require less transmission for their connection. Future ISPs will continue to reassess the most cost-effective balance between transmission and the other system elements.

In *Green Energy Exports*, the NEM would support major new export industries: green energy exported as hydrogen or used to power low-emission heavy industry. This would require hydrogen electrolysers near existing export ports, served by associated transmission. The less likely *Green Energy Exports* would require 10,000 km of network in the next decade, and a total of 26,000 km through to 2050, with the additional capacity focused on areas useful for export such as ports.

Figure 18 New transmission in least cost development paths (kms, 2022-23 to 2049-50)



5.2 Committed and anticipated projects

These projects already have regulatory approval and are highly likely to proceed. They are included in the modelling for all development paths, scenarios and sensitivities:

- **committed network projects** meet all five commitment criteria[24] (site acquisition, components ordered, planning approvals, finance completion and set construction timing), and
- **anticipated network projects** are in the process of meeting at least three of those criteria.

Table 5 Committed and anticipated network projects in the ODP

Status	Project	Description	Full capacity timing (advised by proponent)
Committed	**Far North Queensland REZ**	Uplift of an existing 132 kilovolts (kV) circuit into Woree to 275 kV.	April 2024, Powerlink
	Project EnergyConnect	A new 330 kV double-circuit interconnector between South Australia and New South Wales.	Stage 1 July 2024 and Stage 2 July 2026[A], Transgrid and ElectraNet
Anticipated	**Western Renewables Link**	A 500 kV double-circuit network upgrade to provide additional capacity to the Western Victoria REZ.	July 2027, AEMO Victoria Planning
Anticipated	**Central-West Orana REZ Transmission Link**	A network upgrade consisting of 500 kV and 330 kV circuits to provide additional capacity to the Central West Orana REZ.	August 2028, EnergyCo
Anticipated	**CopperString 2032**	An 840 km new double-circuit line to connect Queensland's North-West Minerals Province to the NEM near Townsville, as announced by the Queensland Government.	June 2029, Powerlink

A. The capacity release and timing is conditional on availability of suitable market conditions and good test results.

5.3 Actionable projects

Actionable projects are listed in Table 6, including delivery dates provided by project proponents. Appendix 5 provides detailed technical information on each project, including the identified need, progress and next steps, and optimal timing to optimise benefits for consumers consistent with the ISP modelling used to derive the ODP.

All actionable projects should progress as urgently as possible. Although Table 6 provides the project proponents' delivery dates, the optimal timing under the ODP may be earlier or later. Earlier delivery would provide valuable insurance against early coal closures or if the development of generation and storage slows.

For projects actioned under the ISP framework, the proponent must assess the project under the RIT-T as detailed below. For those actioned under state frameworks, the processes in that legislation apply.

[24] In accordance with the AER's Cost Benefit Analysis Guidelines accessible at https://www.aer.gov.au/system/files/AER%20-%20Cost%20benefit%20analysis%20guidelines%20-%2025%20August%202020.pdf.

Table 6 Actionable network projects in the optimal development path

Project	In service timing advised by proponent	Full capacity timing advised by proponent	Brief description Cost estimates in $2023	Actionable framework
HumeLink[A]	Northern Circuit July 2026 Southern Circuit December 2026	Northern Circuit July 2026 Southern Circuit December 2026	A 500 kV transmission upgrade connecting Project EnergyConnect and the Snowy Mountains Hydroelectric Scheme to Bannaby. $4,892 million (-5% to +12%)	ISP
Sydney Ring *(Hunter Transmission Project and investigations on southern network options)*	December 2027	December 2027	High capacity 500 kV transmission network to reinforce supply to Sydney, Newcastle and Wollongong load centres. $926 million ±50% (northern option)	New South Wales[B]
New England REZ Transmission Link	September 2028	September 2028	Three separate projects to increase the transfer capability between central and northern New South Wales, enable more transfer capacity out of the Queensland New South Wales Interconnector, and expand the New England REZ. $3.69 billion ± 50%. This cost estimate includes the three separate projects. The scope of this project is subject to ongoing consultation with EnergyCo.	New South Wales[B]
Project Marinus[C]	Stage 1 June 2030 Stage 2 June 2032	Stage 1 December 2030 Stage 2 December 2032	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, to enable more efficient power sharing between these regions. HVAC network assets in Tasmania for REZs under the North West Transmission Developments project. Stage 1: $3.8 billion ± 30% Stage 2: $2.7 billion ± 30%	ISP
Victoria – New South Wales Inteerconnector West (VNI West)	December 2028	December 2029	A new high capacity 500 kV double-circuit line to connect Western Renewables Link (from Bulgana) with Project EnergyConnect and HumeLink (at Dinawan) via a new substation near Kerang. $3.6 billion ±30 %.	ISP
Gladstone Grid Reinforcement[D]	September 2029	September 2029	Increase network capacity from Central Queensland into the Gladstone area to support the area's industry once Gladstone Power Station retires and add capacity between Northern and Southern Queensland. $1.3 billion ± 50%.	Queensland[E]
Queensland SuperGrid South[D, E]	June 2031	June 2031	Stage 2 of the Queensland SuperGrid, under the Queensland Energy and Jobs Plan, to greatly increase the transfer limit between Central and Southern Queensland and connect to the Borumba Pumped Hydro project. $3.3 billion ± 50%.	Queensland[E]

A. 'Northern Circuit' is between Bannaby and Gugaa. 'Southern Circuit' is between Bannaby and Maragle, and Maragle and Gugaa. Transgrid has advised the Southern Circuit has been programmed to December 2026 for optimal delivery.
B. These are actionable New South Wales projects. They will progress under the *Electricity Infrastructure Investment Act 2020* (NSW) rather than the ISP framework. New England REZ Transmission Link includes additional scope compared to 2022 ISP, with the proponent date only applying to the original scope.

C. Project Marinus includes MarinusLink and North West Transmission Developments (NWTD) projects. Project proponent dates represent modelling dates and are under negotiation. Stage 1 refers to Cable 1 and associated NWTD works, and Stage 2 refers to Cable 2 and associated NWTD works. Project Marinus is a single actionable ISP project without decision rules.
D. These are actionable Queensland projects. They may progress under the *Energy (Renewable Transformation and Jobs) Bill* 2023 (Qld) rather than the ISP framework.
E. Project proponent dates are subject to further refinement.

5.4 Future projects

Future ISP projects will deliver net market benefits to consumers, and are forecast to be actionable in the future. The projects and their timings are identified in Table 7 below and detailed in Appendix 5. The timings are indicative, as they will depend on which scenario unfolds in future.

If a project is intended to proceed under the ISP framework, a RIT-T is not required yet. Proponents may start planning and engaging with communities now, if appropriate, to ensure the projects optimise long-term benefits for consumers.

Table 7 Future ISP projects in the optimal development path

Project	Optimal timing *Step Change*	Earliest feasible delivery date	Brief description Cost estimate in $2023
Interconnectors			
QNI Connect	2033-34	2030-31	Adds capacity between southern Queensland and New England, following development of the New England REZ Transmission Link. $2,518 million (±50%).
New South Wales			
Central-West Orana REZ Extension	2040-41	2030-31	Follows the initial Central-West Orana Transmission Link (Anticipated project) to enable additional REZ capacity. Upgrades existing transmission lines to 500 kV. $243 million (±50%).
Hunter-Central Coast REZ Extension	Option 2: 2029-30 Option 2a: 2044-45	Option 2: 2027-28 Option 2a: 2030-31	Adds two transfer capacity upgrades from the REZ to Sydney-Newcastle-Wollongong via Singleton. Further joint planning is required to clarify whether the capacity for this future ISP project can be achieved. This project may change for the final 2024 ISP. $59 million (±50%) for Option 2. $106 million (±50%) for Option 2a.
Cooma-Monaro REZ Extension	2045-46	2030-31	Enables transfer capacity for the Cooma-Monaro REZ in New South Wales. $512 million (±50%).
Queensland			
Queensland SuperGrid North	Timing dependent on Queensland Government policy decisions	2032-33	Adds transfer capacity between Central and North Queensland, while enabling build of a further 3 GW of renewable generation across Northern Queensland, Barcaldine and Isaac REZs and a further 800 MW of renewable generation to be built in the North Queensland Clean Energy Hub REZ. $4,184 million (±50%). SuperGrid North's timing depends on the approval of Pioneer-Burdekin, which is currently progressing through Queensland decision-making processes and does not yet meet the criteria to be an anticipated project for the ISP. AEMO recognises the Queensland Government's commitment to build SuperGrid North

Project	Optimal timing *Step Change*	Earliest feasible delivery date	Brief description Cost estimate in $2023
			and understands that this project may become an actionable Queensland project in the future.
Darling Downs REZ Extension	2034-35	2027-28	Enables additional renewable generation to be dispatched in Darling Downs REZ. $28 million (±50%). The Darling Downs REZ Extension will also facilitate transmission of this generation to load centres in the locality of Brisbane.
Facilitating Power to Central Queensland	2035-36	2030-31	This upgrade option would improve the generation capacity across Northern Queensland, facilitate transmission of generation to load centres in Central Queensland, and support further renewable generation to be dispatched across Isaac and Barcaldine REZ. $173 million (±50%).
North Queensland Energy Hub Expansion	2042-43	2030-31	The North Queensland Clean Energy Hub REZ is at the north-western section of Powerlink's network and has excellent wind and solar resources. While AEMO is now considering the CopperString 2032 project as an anticipated project after outcomes from joint planning with Powerlink and the Queensland Government, the ISP recommends further expansion of the REZ to further unlock renewable resources. The Energy Hub expansion would allow additional renewable generation to be dispatched in North Queensland Clean Energy Hub REZ. $651 million (±30%).
South Australia			
Mid-North REZ Expansion	Option 1: 2045-46 Option 2: 2045-46	Option 1: 2027-28 Option 2: 2027-28	These upgrades would enable renewable generation potential in South Australia's Mid North, Yorke Peninsula, Leigh Creek, Roxby Downs, Eastern Eyre and Western Eyre Peninsula REZs to supply the Adelaide region. AEMO notes that transmission capacity required within South Australia is highly related to load commitment in that region. AEMO and ElectraNet will undertake joint planning between the Draft 2024 ISP and final 2024 ISP on this matter. $416 million (±50%) for Option 1. $740 million (±50%) for Option 2.
Tasmania			
North West Tasmania REZ Expansion	2029-30	2027-28	The North West Tasmania REZ extension project unlocks hosting capacity for variable renewable generation in this REZ, providing additional transmission capacity after Project Marinus Stage 1 is built. This project provides opportunity for high quality renewable generation resources from this REZ to be exported over to the mainland through MarinusLink and increases the transfer capacity between Sheffield to Hampshire Hills where potential generation could come in. $28 million (±30%).
Waddamana to Palmerston transfer capability upgrade	Option 1: 2029-30 Option 2: 2041-42	Option 1: 2027-28 Option 2: 2032-33	The Waddamana to Palmerston transfer capability upgrade in the Central Highlands REZ would unlock hosting capacity for renewable generation in this REZ, providing additional transmission capacity after Project Marinus Stage 1 is built and also additional capacity after Project Marinus Stage 2 is built.

Project	Optimal timing *Step Change*	Earliest feasible delivery date	Brief description Cost estimate in $2023
			This project provides opportunity for high quality variable renewable energy resources from this REZ to be exported over to the mainland through MarinusLink. $201 million (±30%) for Option 1. $274 million (±30%) for Option 2.
Victoria			
Western Victoria Grid Reinforcement	2034-35	2032-33	The Western Victoria Grid Reinforcement project increases transfer capacity out of South-West Victoria REZ to consumers. The project is considered a future ISP project and was formulated through preparatory activities undertaken by AEMO Victorian Planning as an outcome from the 2022 ISP. This project would facilitate development of high quality onshore and offshore renewable generation through South-West Victoria. Cost is $1,297 million (±30%). AEMO National Planning is undertaking joint planning with AEMO Victorian Planning and VicGrid to further investigate options that support onshore and offshore renewable generation development, including through the VicGrid-led Victorian Transmission Plan process, and will incorporate these into the final 2024 ISP.
Eastern Victoria Grid Reinforcement	2035-36	2030-31	Modelling identifies a need for additional transfer capacity between Latrobe Valley and Melbourne to accommodate increased onshore and new offshore wind power generation. The Victorian Government has outlined its vision for offshore wind and has set targets for 2 GW of offshore wind capacity by 2032, 4 GW by 2035 and 9 GW by 2040. The 2023 *Victorian Annual Planning Report* (VAPR) identified emerging limitations in the Melbourne Eastern Metro network. AEMO Victorian Planning has proposed network reconfiguration at Hazelwood 220 kV switchyard for after the retirement of the Yallourn Power Station, to utilise 220 kV lines between Latrobe Valley and Melbourne. In addition, more transfer capacity from Latrobe Valley to Melbourne would be required. AEMO National Planning is undertaking joint planning with AEMO Victorian Planning to incorporate preferred options to address Melbourne Eastern Metro network constraints and possible additional options to increase the existing capacity between the Latrobe Valley and Melbourne, and will incorporate these in to the final 2024 ISP. No cost is provided as options are being joint planned. ISP modelling provides transmission capacity uplift using options provided in the 2023 *Transmission Expansion Options Report.*

6 Storage and gas to firm renewables

Renewable energy connected by transmission, **firmed with storage and backed up by gas** is the lowest cost way to supply electricity to homes and businesses throughout Australia's transition to a net zero economy.

While hydro generation is consistent, solar and wind are variable resources, so different forms of storage and firming are needed across the NEM to smooth out the peaks and troughs in renewable generation.

Storage technologies (which include battery and pumped hydro systems) store electricity when supply is greater than demand, then release or 'dispatch' it when needed. The time between storage and dispatch is a time 'shift' in electricity supply.

Storage, along with hydro and gas generation and other investments, also 'firm' up the renewables to help maintain grid stability and inertia, smooth out volatile frequencies, and balance out fast changes in supply and demand.

Gas generation can provide back-up supply during long periods of 'dark and still' renewable droughts, particularly in the winter, and rare times of extreme peak demand.

These technologies play different yet overlapping roles. The ISP seeks the most efficient balance between them to meet its reliability, affordability and emission priorities. This is then balanced with transmission: the less transmission there is, the more firming capacity is needed, and vice versa.

Section 6 sets out how the optimal development path would provide:

6.1 **Storage of varied depths and technologies**, able to time-shift electricity supply for up to 4 hours, 12 hours, or longer.

6.2 **Storage for intra-day shifting**, including consumer-owned batteries, and shallow and medium utility-scale storage.

6.3 **Storage for seasonal shifting and renewable droughts**, including pumped hydro and hydro generation, with new potential technologies emerging.

6.4 **Flexible gas generation** to support storages during renewable droughts and cover rare peak demand spikes.

6.5 **Reliability and security in a renewable energy power system**, secured through the range of solutions to provide system services traditionally provided by coal.

This section completes a description of the ISP's optimal development path. Section 7 then sets out why this path has been chosen as the lowest cost way to securely and reliably supply electricity to homes and businesses throughout Australia's transition to a net zero economy.

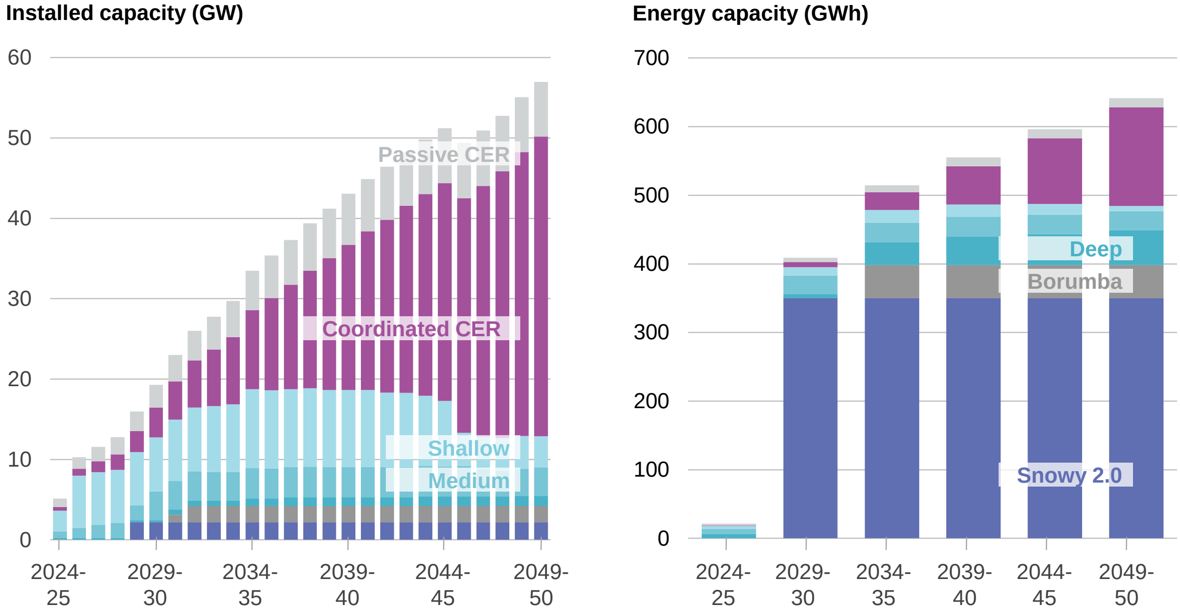
6.1 Storage of varied depths and technologies

Different forms of storage are needed to firm both consumer-owned and utility-scale renewables at different times of the day and year. These vary according to their 'depth', that is, the length of time that electricity can be dispatched at maximum output before the stored energy is exhausted.

In total, the NEM is forecast to need 33 GW / 514 GWh of storage capacity in 2034-35, rising to 57 GW / 642 GWh of storage capacity in 2049-50. The broad categories used by AEMO are:

- **Consumer-owned storage** (or distributed or CER storage): behind-the-meter household, business or industrial batteries, including EVs that may be able to send electricity back into the grid. **Coordinated CER storage** is managed as part of a virtual power plant, while **passive CER storage** is not. While the combined installed capacity of these batteries is large, they can only dispatch electricity for about two hours at full discharge, so their energy storage capacity is relatively small, and deeper, utility-scale storage is needed.
- **Shallow storage**: grid-connected storage to dispatch electricity for less than four hours, valued for both their system services and their energy value.
- **Medium storage:** to dispatch electricity for four to 12 hours. This may be battery or pumped hydro (or other emerging technologies in future) which can shift large quantities of electricity to meet evening or morning peaks. These solutions are increasingly needed to support renewable energy growth.
- **Deep storage:** strategic reserves that can dispatch electricity for more than 12 hours, to shift energy over weeks or months (seasonal shifting) or cover long periods of low sunlight and wind (renewable droughts), backed up by gas-powered generation. Borumba's anticipated 48 GWh capacity in Queensland would be larger than all coordinated CER storage combined, and Snowy 2.0 would provide 350 GWh.

Figure 19 Storage installed capacity and energy storage capacity, NEM (2024-25 to 2049-50, *Step Change*)



6.2 Storage for intra-day shifting

Intra-day shifting is achieved through both consumer-owned storage and shallow utility storage, with the latter also focused on power system services.

In total, approximately 12.7 GW of utility-scale storage is forecast to be needed by 2030, with an optimal mix of 2.4 GW as deep, 3.6 GW as medium and 6.7 GW as shallow storage: see Figure 19.

Growth in consumer energy resources

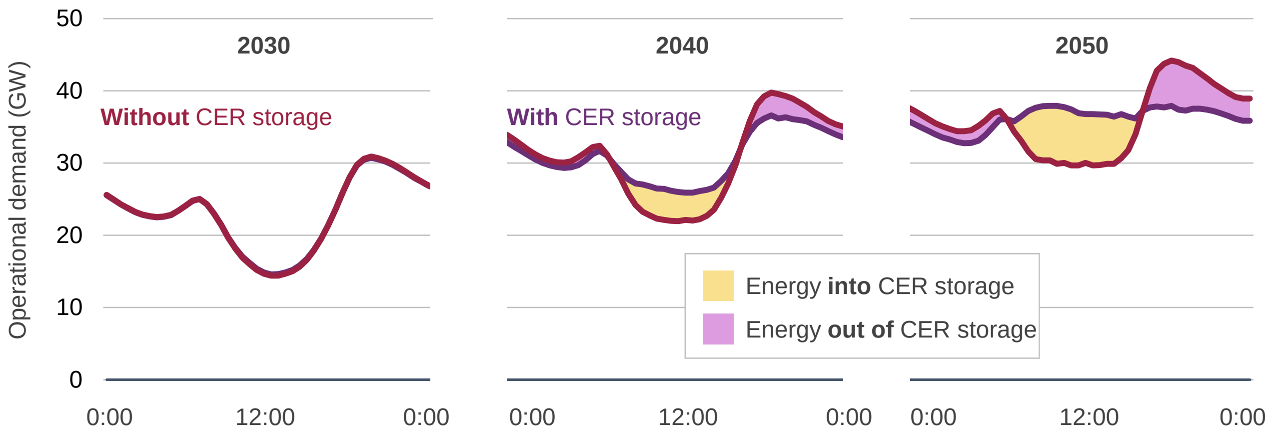
For the NEM as a whole, the three charts in Figure 20 (over page) show the rising impact of consumer-owned solar and batteries on forecast hour-by-hour grid demand. They help smooth out the NEM operational demand curve considerably.

As the sun rises, rooftop solar starts to meet demand, and then generates excess supply (the yellow 'belly' of the 'duck'-shaped demand profile). That excess may be stored for later use during the evening peaks and into the night, or shared with local consumers to reduce the community's need from the grid at that time.

Consumers may take advantage of financial incentives to add smart functionality and coordinate their batteries through VPPs, so that they can help balance supply and demand across the grid. The success of trials such as Project EDGE will help build consumer confidence to do so.

The capacity of these coordinated CER storages is forecast to rise from today's 0.2 GW to 3.7 GW in 2029-30, and then 37 GW in 2049-50 – by then making up 65% of the NEM's energy storage capacity.

Figure 20 Impact of coordinated CER on average operational demand by time of day, NEM (GW, 2030 to 2050, *Step Change*)



Growth in utility-scale batteries

Many utility-scale batteries are already installed across the NEM, with a large pipeline being developed or seeking connection to the grid. These batteries are designed to dispatch electricity instantaneously, and so support grid security with frequency control ancillary services (FCAS) as well as storing excess electricity: see Section 6.5 below.

In future, the longer-duration role will also be served by pumped hydro storage, and potentially by emerging technologies like advanced compressed air energy storage, gravitational storage, flow batteries and concentrated solar thermal systems.

While batteries are relatively low cost to install, they also have a relatively short operational lifespan. Batteries installed through the 2020s are likely to need replacing in the 2040s. This explains the drop in shallow storage in that decade, in Figure 19 above. By then, deeper storage options may be needed to cover the more volatile winter season, while summer needs are met by the growth in rooftop solar. These solutions are forecast to include flexible gas generation capable of providing sustained support during renewable droughts.

6.3 Storage for seasonal shifting and renewable droughts

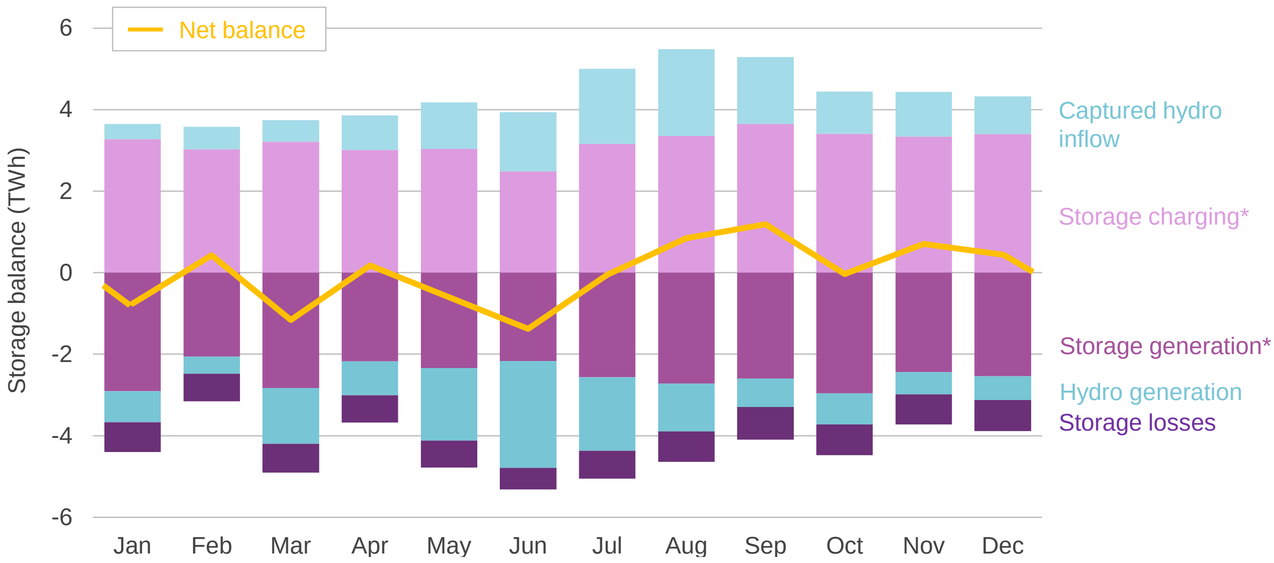
Deep storage, able to dispatch electricity for more than 12 hours continuously, can smooth out day-to-day variations in demand and renewable supply. The deepest storage available to the NEM are its existing deep-reservoir hydro assets, which can also mitigate renewable droughts and balance energy across seasons. New transmission such as HumeLink and Project Marinus gives the NEM better access to these assets.

A number of government programs support the development of new deep (or medium) storage, but at this stage only Snowy 2.0 (serving New South Wales and Victoria), and Borumba and Kidston (Queensland) are committed or anticipated. Queensland is also considering a deep Pioneer-Burdekin project, Hydro Tasmania is investigating a new pumped hydro Battery of the Nation initiative at Cethana, and New South Wales has legislated a 2 GW target for storage of at least 8 hours duration by 2030.

Figure 21 shows an 'average' future year to demonstrate the key role that traditional hydro and storage play across seasons. In summer, the NEM system is almost in balance across the months, with any used storage being replenished by solar. Into autumn, with typically more variable winds and decreasing sunlight, more energy starts to be drawn from hydro reservoirs. These will play their biggest role in winter, supported by gas, when heating demands are high, solar is reduced, and wind can be strong but intermittent. In June, storage and hydro generation would supply almost 4 TWh of electricity across the NEM, drawing down water reservoirs to low levels. Through August and into spring, snowmelt and higher rainfalls replenish those dams. Solar starts to generate again more than is consumed, bringing the system back into balance.

Sound planning and energy management seek to minimise the need for deep storage and gas back up. However, forecasting both energy demand and weather can never be perfect. It is prudent to provide a buffer of deeper solutions to add resilience against known yet unpredictable risks. Market and policy settings will need to evolve to enable deep storage solutions with cost recovery mechanisms that are not limited to actual usage.

Figure 21 **Storage and hydro energy balances, NEM** (TWh, 2040, Step Change)



Note: Pumped hydro included as large-scale storage, not as hydro

6.4 Flexible gas for renewable droughts and peaking

Electricity from gas-powered generation (GPG) is forecast to continue its important role in the NEM. After coal-fired generators retire, gas will be needed to support energy supply during periods of renewable drought (see Section 6.5) and of extreme peak demand (see below). Gas supply and potentially a hydrogen alternative also need consideration.

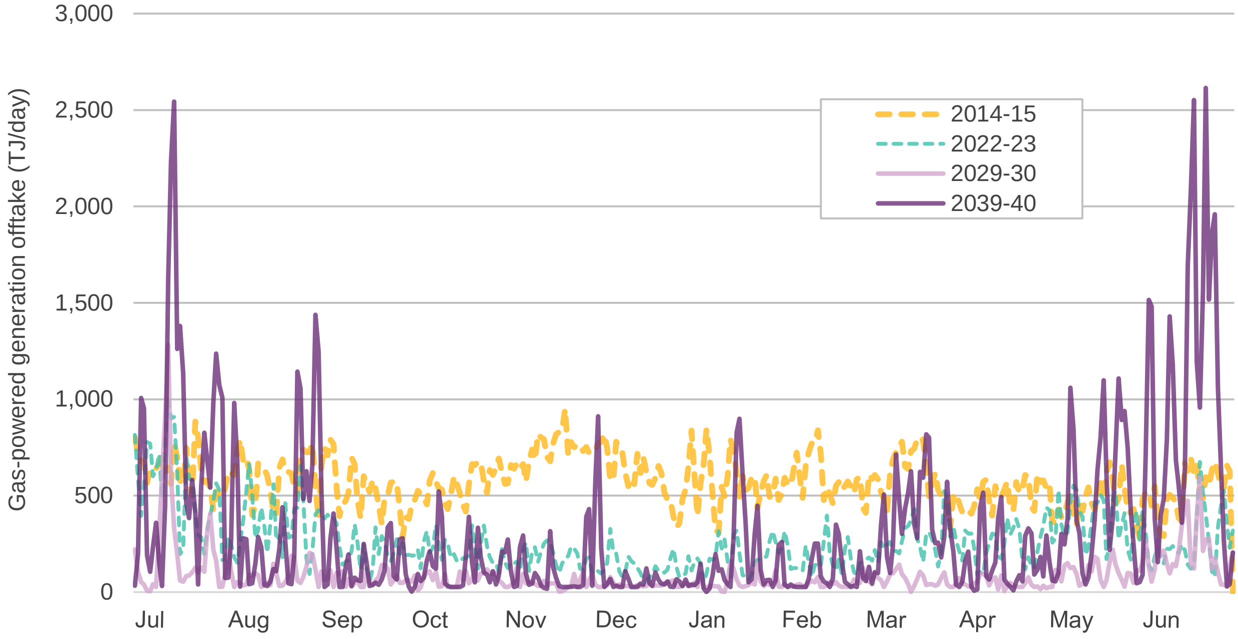
Growth in flexible gas generation

In total, the NEM is forecast to need 16.2 GW of gas-powered generation. Of the existing 11.2 GW capacity, about 8 GW is forecast or announced to retire, so that capacity would be replaced and another 5 GW added. This may be either as greenfield or brownfield development, but the gas generation must be flexible.

This gas generation is a strategic reserve for power system reliability and security, so is not forecast to run frequently. A typical gas generator may generate just 5% of its annual potential, but will be critical when it runs. Most of that will be needed some days in winter, for the reasons discussed in Section 6.3 above.

This is a change in the role of GPG from more continuous 'mid-merit' gas to a strategic, back-up role. Figure 22 shows that change in role, from relatively stable supply in 2015, to the forecast winter peaks in 2040. These peaks are forecast to test the limitations of the gas supply network, and solutions will be needed to address them.

Figure 22 Gas-powered generation offtake, NEM (TJ/day 2014-15 and 2039-40, *Step Change*)



Gas network impacts on gas powered generation

Gas for electricity generation is expected to be needed most during winter, when gas demand for heating is also high. Its availability depends on gas supplies through the East Coast gas system.

AEMO forecasts that if gas and electricity demands peak simultaneously, particularly during extreme conditions in winter affecting both electricity and gas demand, then there is a risk that gas supply to gas-powered generation may be curtailed by pipeline infrastructure constraints. During such conditions, use of locally stored secondary fuels (such as diesel or hydrogen), demand response, or other firming resources may be used to maintain reliable electricity supply. More on-site gas, diesel or hydrogen storages may be needed to secure this strategic reserve.

Avoiding gas network bottlenecks should also be considered in siting new gas-powered generation. Location decisions for new generators will need to consider availability of gas infrastructure (including pipelines and gas storages), future gas supplies, secondary fuels and proximity to electrical loads.

Hydrogen as a potential alternative generation fuel

Some gas generators may be configured to use an alternative fuel, such as diesel, bio-diesel, hydrogen or even a mix of those. Policies in New South Wales, South Australia and Queensland are supporting investment in hydrogen-ready turbines. The Draft 2024 ISP forecasts only a small contribution from this technology, as hydrogen is still a relatively expensive fuel to use at scale. If hydrogen becomes a cost-efficient fuel, or there is greater government support for hydrogen turbines, they will make a greater contribution.

6.5 Reliability and security in a system dominated by renewables

The challenge for the NEM power system is to be consistently reliable and secure: see Section 3.2. This becomes more challenging as the system approaches 100% renewable generation. Consumers should feel confident that the NEM's mix of technologies will keep electricity supply secure and reliable during normal operation, extreme peak demand and renewable droughts.

System secure due to system services from batteries and other technologies

The heavy spinning turbines of coal, gas and hydro generators have multiple intrinsic benefits beyond their actual generation. For example:

- they spin at a rate that lines up with the electrical frequency of the power grid that they supply ('synchronous generation'),
- this, coupled with the physical spinning momentum, adds 'inertia' to help resist unwanted changes to the system frequency, and
- if a fault occurs somewhere in the system, the generators can add needed current to the system so that protections can operate until the fault can be isolated.

These 'system security services' help the power system stay stable and secure. As coal generators retire, the NEM will lose these services, and they will need to be replaced.

System security services may be replicated by other technologies, for example grid batteries with advanced inverter technology, synchronous condensers[25], and gas and hydro generators that can operate in synchronous condenser mode. These solutions would produce synthetic responses to resist frequency changes, provide needed fault current, or strengthen local areas against challenging volatility and interactions: see Appendix 7.[26]

Batteries also improve the utilisation of new and existing transmission lines. Several large-scale grid batteries[27] are contracted to provide system integrity protection services. Some of their capacity is held in reserve to inject power on short notice to help stabilise the lines and allowing the lines to operate at higher levels. This reserve can increase the capacity of congested grids, so that new renewable generation can be connected.

System reliable during peak demand and renewable 'droughts'

Peak demand is forecast to be met within the reliability standard throughout the entire forecast period, through combinations of renewable generation and storage, backed up at times by gas when required: see Section 6.4 above.

[25] Synchronous condensers are synchronous machines, specially built to supply only reactive power.

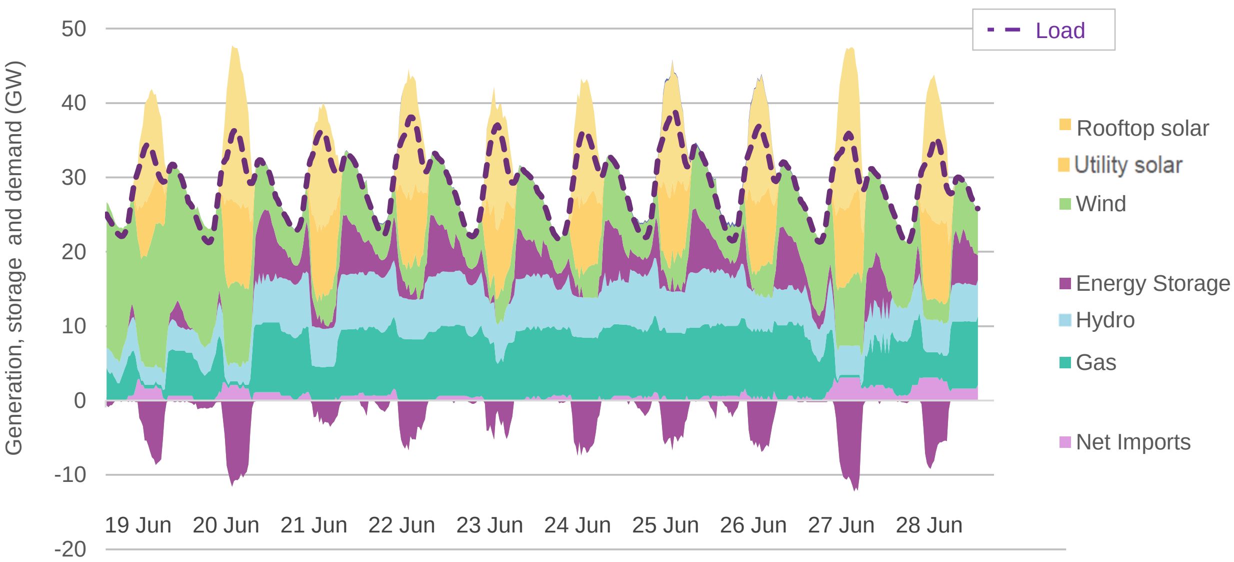
[26] Note that the ISP modelling is an energy-only model and does not consider the co-optimisation of batteries for both their energy dispatch and system service roles. AEMO takes this conservative approach as it expects FCAS markets to remain of finite depth and quickly saturate as more battery projects connect.

[27] AEMO has contracted the Waratah Super Battery, Victorian Big Battery, Hornsdale Power Reserve and the Dalrymple Battery Energy Storage System in the System Integrity Protection Scheme (SIPS).

Renewable droughts are common, local events that typically last a few hours or a day or two, and are more likely in winter when there is less solar irradiation (energy) and shorter daylight hours. Assuming new transmission is delivered as planned, renewable resources can be shared across the NEM, leaving only renewable droughts that affect considerable portions of the NEM as the key concern.

Historical weather patterns suggest that longer 'dark and still' periods of up to 3 days covering a wide geographical area are rare, with low risk of a NEM-wide event. However future weather may not replicate the past, especially with climate change, so there may be longer and more widespread renewable droughts. AEMO therefore tested the ODP to see whether it could meet the reliability standard through drought conditions across the southern regions of the NEM for eight days – a period at least twice as long and more severe than any since 2010, and possibly since 1980[28]. The test showed that the power system would remain reliable and secure (see Figure 23) but reliability risks would be elevated, particularly if major generator or transmission outages occur.

Figure 23 Operability through eight-day renewable drought, NEM except Queensland



[28] AEMO's ISP modelling applies weather patterns from 2010-11 to 2019-20 to analyse the future operability of the power system. Wind records back to 1980 show similar average wind and a comparable spread of extremely high or low wind speed events.

7 Rationale for the ODP

Renewable energy connected by transmission, firmed with storage and backed up by gas **is the lowest-cost way to supply electricity to homes and businesses throughout Australia's transition to a net zero economy**.

Part B laid out the major elements of the ISP's optimal development path: by 2050 it forecasts 126 GW of utility-scale renewables, 86 GW of rooftop solar and other distributed solar, 74 GW of firming technology, and new transmission and modernised distribution networks will connect these assets to consumers.

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*. It considers:

7.1 The reliability and cost-benefits of the ODP as a whole.

7.2 How the leading candidate development paths were developed and analysed following the *ISP Methodology*, and why the ODP was chosen, after testing the leading candidate development paths against changed assumptions.

7.3 Why the ODP delivers better outcomes to consumers than alternative approaches to the energy system.

Appendix 6 provides full details about the selection of the ODP.

7.1 Reliability and cost benefits of the ODP

Investment in new generation, firming and transmission is essential to replace outgoing coal generation. The selected ODP ensures that the NEM continues to meet the reliability standard and puts downward pressure on energy costs through the energy transition. All of the transmission projects in the ODP are needed. Overall, the ODP investments would:

- optimise benefits for all who produce, consume and transport electricity in the market,
- provide both investment certainty and the flexibility to reduce emissions faster if needed,
- guide $121 billion in essential capital investment to help sustain and grow Australia's $2 trillion annual economy and the social services on which its people depend,
- progress $16.4 billion in transmission investment[29] that would deliver $17 billion in net market benefits to consumers (see below),
- connect emerging areas of renewable generation to regional industries and urban businesses and households,
- firm variable renewable energy with batteries, pumped hydro storage and gas-powered generation, and

[29] This value does not include the cost of commissioned, committed or anticipated projects.

- create new economic and job opportunities, particularly in regional areas.

The annualised capital cost of all generation, storage, firming and transmission infrastructure in the ODP has a present value of $121 billion in the *Step Change* scenario to 2050[30]. Of this cost, transmission projects amount to $16.4 billion, or 13.5% of the total. This would pay itself back, and deliver the additional $17 billion net market benefit noted above. The equivalent upfront capital cost for generation, storage, firming and transmission infrastructure in the ODP has a present value of $138 billion in the *Step Change* scenario to 2050 (as some technical life remains after 2050 for the long-lived assets).

7.2 Identifying the optimal development path

AEMO has considered over 1,000 potential development paths of new transmission investments to support the generation, storage and CER developments needed, and whittled them down to a final shortlist of 18 candidate development paths. These include a 'counterfactual' path that has no new major network projects beyond those already committed or anticipated.

To select the ODP from these candidate development paths, AEMO follows the steps provided by the AER's cost benefit analysis guidelines and detailed in the *ISP Methodology.* This section sets out that methodology in brief, with Appendix 6 setting out in detail the approach and findings of each step.

Identify and 'rank' the strongest candidate development paths

- **Determine the least-cost development path for each scenario.** These three candidate development paths would maximise net market benefits under their respective scenarios. They include a similar set of transmission projects. These projects deliver net market benefits in all scenarios, though their optimal timings (and so potential actionability) differ across the scenarios.
- **Determine a shortlist set of candidate development paths to assess.** The least-cost development path in the most likely *Step Change* scenario was the basis for other candidate development paths. To form a new candidate development path, projects were either pushed back towards their later *Progressive Change* timing, or brought forward towards their earlier *Green Energy Exports* timing.
- **Assess and rank each candidate.** Two assessments were made to rank the candidate development paths. The first 'risk neutral' assessment was of net market benefits across the three scenarios. The second 'risk averse' assessment was of the regret costs, which are the benefits that are lost if projects are planned and delivered for one scenario, but another scenario plays out. These rankings take into account the likelihood of the scenarios occurring: see Section 3.3.

Several candidate development paths had a similar set of transmission projects, similar net market benefits, and similar 'regret' costs, and two stood out on both rankings.

[30] This value does not include the cost of commissioned, committed or anticipated projects.

Test candidate development paths against sensitivities and consumer risk attitudes

AEMO then tests how the candidate development paths perform when key assumptions (or 'sensitivities') are changed, and considers consumer attitudes to risk (see Section 3.2). AEMO can use these additional tests to select the ODP, in its professional judgement.

The tested sensitivities were on the speed of decarbonisation, the level of energy efficiency measures, alternatives to electrification, constrained supply chains, the impact of major pumped hydro projects, and a higher and lower discount rate. A new sensitivity was one of reduced social licence, developed with input from ISP Consumer Panel and the Advisory Council on Social Licence: see Appendix 8.

The analysis showed that the benefits changed materially with levels of deep storage assets and energy efficiency. However, the top-ranking candidate development paths still delivered high net market benefits (they were robust to the sensitivities), and there was minimal impact on their relative rankings. If anything, the sensitivities slightly favoured the candidate that maximised the net market benefits to consumers. This candidate also had very low regret costs. Given these findings, AEMO did not further consider consumer attitudes to risk in selecting the ODP.

The ODP includes the list of actionable and future projects that have been outlined in Chapter 5.

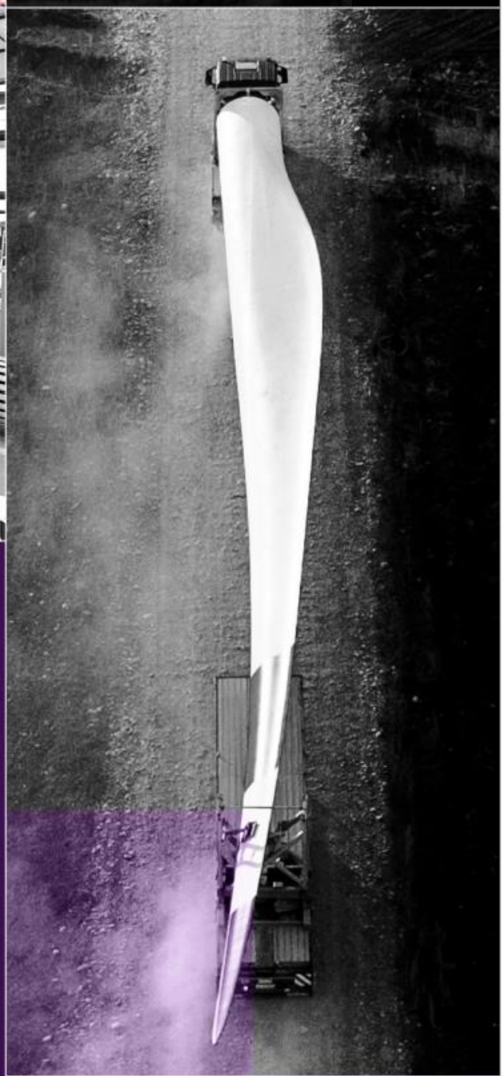
7.3 Alternative approaches to the ODP

The ODP is a resilient, pragmatic path to the NEM's energy future that maximises net market benefits for consumers. The potential development paths included different balances between generation, storage and transmission, and were assessed against different levels of consumer-owned assets. Cost assessments have explored alternatives such as the undergrounding of transmission, replacing coal with gas and carbon capture and storage, and the impacts of large hydro developments.

Alternative paths result in either more reliability risks or greater costs or both, and many substantially so. For example, regional landholders and communities have very reasonably raised underground cables as an alternative in visually sensitive areas. However, their costs range from four to 20 times higher than overhead lines, depending on their voltage, capacity, the use of tunnels and other design factors. Given the length of Australian transmission projects, the cost of undergrounding is often prohibitive and can only be considered in limited cases. It may be feasible for connecting a generation asset to the grid, if the distance is short and the cost can be incorporated into the business case of that asset. These issues will continue to be explored through The Energy Charter's 'Evaluating Transmission Undergrounding' initiative and the second New South Wales Government's Inquiry into Transmission Undergrounding.

Similarly, investing in more gas-powered generation combined with carbon capture and storage depends on several site and technology assumptions for such a plant to be feasible. In any case, the ODP provides for the gas generation that is needed, and renewables are far cheaper for any additional need.

Future ISPs will continue to respond to material changes in technologies, costs and policies.



PART C

Delivering the optimal development path

Part C: Delivering the optimal development path

Seizing the opportunities of the energy transition is critical for our nation. Australia's wind and solar resources offer low-cost electricity as coal retires, and far exceed what we can use ourselves.

AEMO has identified the ODP as the most cost-effective path for maintaining reliable electricity supply as coal retires. If delivered, the ODP would meet electricity consumer needs for at least 20 years, fulfil the NEM's security and reliability requirements, meet government policy settings and manage risk through a complex transformation.

Both the energy transition and the ODP need to be delivered.

In Part C:

- **Section 8 – Risks to delivery of the ODP and to the energy transition.** Investment in infrastructure remains urgent. Yet market and policy settings do not yet address the risks of coal retirement, and social licence and supply chain issues challenge delivery.
- **Section 9 – Finalising the 2024 ISP.** AEMO will continue to take an inclusive and consultative approach. It will consider and respond to submissions on the Draft 2024 ISP, and conduct any further analysis needed to finalise the 2024 ISP.

Identifying the ODP is only a very small contribution to Australia's energy future. It's what happens next that counts.

All industry organisations, including AEMO, must prioritise the important work of delivering a safe, reliable and affordable energy future for Australia.

8 Risks to the ODP and to the energy transition

While significant progress is being made, AEMO is acutely aware of challenges and risks already being experienced and that may grow in the future. Risks to the reliability of the system are already becoming visible, and the NEM must be resilient to shocks such as unanticipated coal closures or outages, intense weather events or, conceivably, cyber attacks.

As well, the affordability of reliable supply is being tested by factors including market policies, project costs, supply chain interruptions or scarcities, cost pressures and investment uncertainty.

This section sets out how:

8.1 **Investment in infrastructure remains urgent** to keep the ODP to its schedule and the transition on track, and so reduce risks and maintain benefits to consumers.

8.2 **Market and policy settings do not yet address the risks of coal retirement.** The ODP relies on policy and market settings that promote competition and innovation, to deliver the efficient, reliable, lower emission electricity services contemplated by the National Electricity Objective.

8.3 **Social licence and supply chain issues continue to challenge delivery.** Planning for such a generational peak in infrastructure investments requires careful management and risk management of financial, supply chain and workforce resources. The transition is equally dependent on consumers and communities being engaged and empowered as part of the energy transition.

Positive action will be needed to ensure these risks are addressed.

8.1 Investment remains urgent to reduce risks

The need for planned investment remains urgent. The possibility of replacement generation not being available when coal plants retire is real and growing, and a risk that must be avoided. Unplanned generator outages are increasing, as coal plant reliability is affected by reduced investment and high-impact weather events.

Any delay to the ODP will increase risks to the energy transition and its benefits. The sooner firmed renewables are connected, the more secure the transition will be. However, progress on planned projects is being slowed by community acceptance, cost pressures, investment uncertainty, supply chain issues and workforce shortages.

The expansion of the federal Capacity Investment Scheme on 23 November 2023 recognises this urgency, giving additional support for the development of 32 GW of new capacity nationally, including 23 GW of renewable energy and 9 GW of clean dispatchable capacity[31].

[31] Australian Government. 'Capacity investment scheme', November 2023. At Capacity Investment Scheme | energy.gov.au.

8.2 Risks that market and policy settings are not yet ready for coal's retirement

Four sets of risks require market settings to be in place if the NEM is to be ready for 100% renewables and for coal plant retirements:

- Risk of uncertainty for infrastructure investment,
- Risk of early retirements of coal-fired generation plants
- Risk that market and power system operations are not ready for 100% renewables, and
- Risk that insufficient consumer energy resources are not adequately integrated into grid operations.

Market and policy settings must be in place to address these risks and keep the energy transition on track.

Risk of uncertainty for infrastructure investment

The energy transition depends on timely investment decisions, which are hampered by uncertainty. Government initiatives such as Long-Term Energy Service Agreements in New South Wales, state-based renewable energy and infrastructure targets, the Capacity Investment Scheme and the Nationally Significant Transmission Project framework help reduce that uncertainty. AEMO strongly supports further market reforms that will expedite investment and effectively balance timely investment with assessment rigour across all forms of infrastructure.

Risk of early coal retirements

While almost all owners of coal generators have announced their long-term retirement plans, they are only required to give three and a half years' notice of a closure, which would leave the NEM very little time to respond. Closures with short notice increase the risk of near-term reliability challenges and price shocks for consumers, and further accelerate the need for new generation. These risks are best mitigated through agreed closure timeframes and delivery of the planned investment in generation capacity.

Risk that markets and power system operations are not yet ready for 100% renewables

Renewable generation is being installed rapidly, but the NEM's energy markets, networks and operations must evolve to be ready for very high penetrations of renewable energy. More action is needed to make sure that system services, resource adequacy and operational capability are in place in time for coal retirements.

AEMO continues to work with governments, market bodies and industry on the technical requirements for a secure power system capable of operating at 100% renewables, and subsequent evolution of market frameworks and settings to deliver those requirements in both investment and operational timeframes.

Risk that CER are not adequately integrated into grid operations

Consumer-owned assets offer significant system benefits and offset the need for grid-scale investment. They offer the potential for significant net market benefits being shared both by their owners and by energy consumers across the NEM: see Section 4.2.

Those benefits are maximised when two things happen:

- First, when owners link up with other owners to coordinate their CER as virtual power plants (VPPs), which is being facilitated by many retail market specialists and among businesses.
- Second, when those VPPs are integrated into the NEM to help support power system reliability and security. This 'orchestration' needs appropriate operational standards between the distribution grid and VPPs, and appropriate incentives and agreements with CER owners.

For this to happen, owners would need to see the benefits of orchestration, overcoming both technical complexity and a lack of perceived value[32], then trust the energy sector to deliver those benefits. AEMO will continue working with industry, governments, market bodies and consumers for the benefits of CER orchestration to be realised.

8.3 Social licence and supply chain risks to delivery

The policy, market and operational settings noted above are largely in the hands of the energy industry. Even if they are in place, delivery of the ODP and the energy transition would not be guaranteed.

The energy industry must also work with communities throughout the NEM, and supply chain partners throughout the world, to ensure there is the social acceptance, equipment, materials and workforce needed to deliver the transition on time.

Risk that social licence for the energy transition is not being earned

Social licence – or the ability of governments, organisations and project developers to build and maintain trust and acceptance with those groups and communities most affected by the impacts, opportunities and challenges the energy transition affords – will be critical in enabling its success.

The ISP is clear in its call for urgent investment in the energy transition. Yet for the energy transition to succeed, community acceptance or social licence is needed in three areas:

- local community acceptance of new infrastructure development,
- owner acceptance for the 'orchestration' of their consumer energy resources (see above), and
- broad social acceptance of the energy transition itself.

Working collaboratively and gaining trust with regional and rural communities is essential to the success of the energy transition. The Draft 2024 ISP highlights the need for significant renewable energy development, particularly within REZs, and for new transmission corridors. AEMO recognises that communities are being asked, for the most part, to host this new energy

[32] Acil Allen. *Barriers and enablers for rewarding consumers for access to flexible DER and energy use*, June 2022. At https://www.datocms-assets.com/32572/1658964119-barriers-and-enablers-final-report-v2-352146-1-3-1.pdf.

infrastructure for the benefit of all energy consumers, for industrial users in regional areas as much as city businesses and households.

Energy institutions, developers and communities are working hard to build the relationships of trust that underpin social licence. Their experience is being captured by the National Guidelines for Social Licence for Transmission, the Australian Energy Infrastructure Commissioner's review of community engagement practices, the Victorian Transmission Investment Framework (VTIF), and the New South Wales First Nations Guidelines for consultation and negotiation with local Aboriginal communities, among other initiatives.

These and like initiatives are critical to building the trust-based relationships needed for the energy transition. Developers and energy institutions must ensure that those being asked to host infrastructure are engaged early, consistently and respectfully; that voices and concerns are considered and responded to; that negative impacts are minimised wherever possible; and that potential opportunities and benefits are maximised and distributed fairly.

AEMO appreciates the input from the 2024 ISP Consumer Panel and Advisory Council on Social Licence in the development of the Draft 2024 ISP, especially their input on a new sensitivity to explore social licence: see Appendix 8.

Risks in securing critical energy assets and workforce

The deep investments required in the ISP imply the need for thousands of critical energy assets – grid-scale generators and batteries, high voltage transmission lines and cables, synchronous condensers and transformers – and the people needed to instal and operate them.

In a global energy transformation, countries are competing for the same materials, technologies and expertise. The stimulus to renewable energy innovation and investment prompted by the *US Inflation Reduction Act* (IRA) has placed a global premium on these assets. Australia may benefit from outcomes of this investment, such as accelerated technology development, although it will increase competition for investment and skills.

This competition may exacerbate three existing risks.

- First, Australia may not be able to access reliable and cost-effective supply of these assets over the next 15 years, as global demand for them rises, and the global supply chain remains vulnerable. Some actionable ISP projects have already experienced schedule delays, and such slippages are likely to continue. A supply chain constraint was tested as a sensitivity for this Draft 2024 ISP, finding that tight constraints may lead to renewable energy and emissions reduction targets being missed. Under the sensitivity analysis, the total renewable energy share would be only 63% by 2030, less than the 82% target, and NEM emissions would overshoot their 2029-30 emissions targets by approximately 155Mt CO_2-e[33].
- The race to net zero may also push up some costs. Transmission cost estimates have increased approximately 30% in real terms over the past two years and future cost reductions are very unlikely[34]. Costs for wind and solar have increased over the past year, largely due to

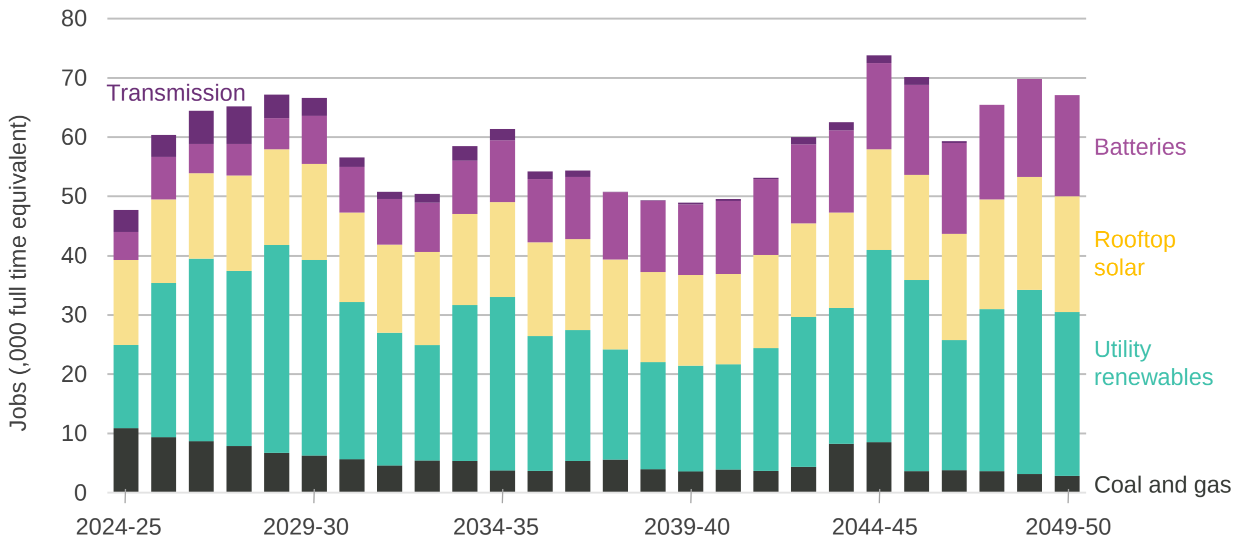
[33] The costs associated with the breach of these policies are not included in the sensitivity's net present value calculations.

[34] AEMO. 2023 Transmission Expansion Options Report, p 4. At https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

pandemic-related supply chain issues, but they are forecast to continue their long-term decline with still further innovation.

- A further risk is that investment is not made in the training and immigration initiatives needed to secure a workforce for the energy transition. A large skilled workforce in Australia, across every discipline not just engineering, is needed for the enormous task ahead. The demand for skilled people directly employed to build new energy infrastructure is forecast to increase from approximately 48,000 in 2025 to over 70,000 across the horizon to 2050[35], in the *Step Change* scenario. This growth will challenge engineering, procurement and construction (EPC) firms and regional communities, particularly if there are boom-and-bust cycles or if workers and contractors are engaged project-to-project.

Figure 24 Workforce needs for CER and utility infrastructure, NEM (2024-25 to 2049-50, *Step Change*)



Early investment will buttress the business case for infrastructure investment. As well, it will mitigate against supply chain risks in future, retain Australia's spot in global queues for essential equipment and materials, and ensure our ability to respond to future market and climate events.

[35] This forecast is an estimate based on the Draft 2024 ISP results, using the workforce projections method provided by the Institute for Sustainable Futures for the 2022 ISP. AEMO will update this forecast for the final 2024 ISP to ensure alignment with the Institute's method and if required to reflect any relevant updates from the Infrastructure Australia *Market Capacity for Electricity Infrastructure* update due for release in December 2023.

9 Progressing the 2024 ISP

AEMO will continue to take a consultative and collaborative approach to prepare the 2024 ISP. Consultation with NEM stakeholders is critical to the ISP and more generally to AEMO's role as the NEM operator and national transmission planner.

This section sets out three streams of inclusive action to complete the 2024 ISP process:

9.1 **Consultation on the Draft ISP**, including a call for written submissions and invitations to participate in a range of additional engagement opportunities.

9.2 **Continued collaboration with industry and stakeholder bodies**. AEMO is committed to ensuring that extensive collaboration and advice informs the outcomes of the 2024 ISP for all jurisdictions.

9.3 **Further analysis in preparation for the 2024 ISP**, including on the distributional effects of the ODP, the power system performance and impacts of actionable projects, and analyses in response to submissions received on the Draft 2024 ISP.

AEMO looks forward to consulting with all stakeholders through to the completion of the 2024 ISP.

9.1 Consultation on the Draft ISP

AEMO welcomes and encourages written submissions from all stakeholders on the Draft 2024 ISP. AEMO has extended the required consultation period in acknowledgement of the summer holiday period and is seeking written submissions by 16 February 2024.

Table 8 lists the consultation and submission dates for the Draft ISP. Stakeholders can register for public and specialised forums (in the form of webinars) through the AEMO website[36].

After the table, AEMO provides guidance on the content of written submissions, as well as information about why AEMO is not calling for submissions on non-network options.

Table 8 Consultation and submission dates for the Draft ISP

Date	Event	Purpose
15 December 2023	Draft ISP published	Consult on the Draft 2024 ISP (including a preliminary optimal development path) and invite written submissions.
20 December 2023	Webinar	A public forum on the Draft ISP, with questions encouraged.
30 January 2024	Consumer Advocate pre-submission webinar	A specialised forum for consumer advocates to ask AEMO questions before submissions are due.
15 February 2024	Consumer Advocate verbal comment session	A specialised forum for consumer advocates to provide verbal comments.
16 February 2024	Written submissions close	Written comments from all stakeholders.
2 April 2024	Webinar	A public forum (date subject to change) to outline the contents of submissions received.

36 At https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/opportunities-for-engagement.

Guidance on written submissions on the Draft ISP

AEMO welcomes and encourages written submissions from all stakeholders on any aspect of the Draft 2024 ISP, including development path outcomes. AEMO particularly welcomes responses to the following questions:

1. Do you that the proposed optimal development path for transmission, generation and storage will support a reliable, secure and affordable NEM?

   If yes, what gives you that confidence? If not, what should be considered further, and why?

2. Do you think that the proposed timing and treatment of actionable projects in the Draft 2024 ISP will support a reliable, secure and affordable NEM? If yes, what gives you that confidence? If not, what should be considered further, and why?
3. Does the Draft 2024 ISP accurately reflect consumers' risk preferences? If yes, how so? If not, how else could consumers' risk preferences be included and what risks do you think are important to consider?
4. Do you have advice about how social licence can be further considered in the ISP, or advice on how to quantify the potential impact of social licence through social licence sensitivity analysis?
5. Do you have any feedback on the Addendum to the 2023 Inputs Assumptions and Scenarios Report, which is published alongside this report?

Written submissions providing feedback on the Draft 2024 ISP should be sent in PDF format to ISP@aemo.com.au and are required to be submitted by 6pm (AEST), Friday 16 February 2024.

AEMO requests that, where possible, submissions should provide evidence and information to support any views or claims that are put forward. AEMO will publish submissions on its website subject materiality and confidentiality requirements[37]. Please identify any parts of your submission that you wish to remain confidential and explain why.

Before submissions close, AEMO will host a 90-minute public forum in the form of a webinar, from 11.30am to 1pm (AEST) on Wednesday 20 December 2023. At the webinar, AEMO will present the key outcomes of the Draft 2024 ISP and will allow time for questions. Stakeholders can sign up to attend the webinar[38], and a recording will be posted on AEMO's website after the webinar[39].

No submissions for non-network solutions

AEMO is not calling for non-network solutions in this Draft 2024 ISP because:

- There are no newly actionable ISP projects in this Draft 2024 ISP.
- A number of previously actionable ISP projects remain actionable, either as actionable ISP projects, or as actionable New South Wales projects. For those projects, non-network options have either already been called for through previous ISP and IASR consultations, or should be

[37] This is consistent with AEMO's obligations under section 54 of the National Electricity Law.

[38] At https://events.teams.microsoft.com/event/7e14c9eb-42f5-490b-b81d-4d385b2ad1bd@320c999e-3876-4ad0-b401-d241068e9e60.

[39] At https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/opportunities-for-engagement.

considered separately through the New South Wales Electricity Infrastrucuture Roadmap framework.

- It has identified two new projects as actionable Queensland projects. For those projects, non-network options may be considered separately through the Queensland Energy and Jobs Plan framework.

9.2 Continued engagement with stakeholders

AEMO thanks all TNSPs and jurisdictional bodies in the NEM for the regular and extensive joint planning undertaken through the development of the Draft 2024 ISP. AEMO will continue to collaborate closely with TNSPs and jurisdictional bodies until the release of the final 2024 ISP to make sure their specialist advice is incorporated in the ISP wherever possible.

AEMO will continue to engage with the ISP Consumer Panel and the Advisory Council on Social Licence. This will include:

- **ISP Consumer Panel.** The panel will provide a report about the Draft 2024 ISP to AEMO, including an assessment of the evidence and reasons supporting AEMO's conclusions in the Draft 2024 ISP, which AEMO will carefully consider in preparing the final 2024 ISP.
- **Advisory Council on Social Licence.** AEMO will continue to seek the council's input as relevant and appropriate on social licence matters.

AEMO thanks all stakeholders who have participated in the 2024 ISP process so far. Leveraging expertise from across industry, consumers and stakeholders is crucial for making sure the ISP remains a robust plan that supports the long-term interests of energy consumers. AEMO looks forward to continued engagement before the release of the final 2024 ISP by 28 June 2024.

9.3 Further analysis in preparation for the final 2024 ISP

AEMO will undertake additional analysis between the draft and final 2024 ISP to further validate the roadmap for the changes to the power system, and to provide additional information for stakeholders, industry and decision-makers.

Further analysis will include:

- The distributional effects of the ODP,
- Power system analysis to verify the performance of actionable projects,
- Sensitivity analysis to understand the impact of passive CER rather than orchestrated CER,
- Inclusion of a Value of Emissions Reduction (VER), if it becomes available,
- Further analysis on the impact of potential new load connection in South Australia due to a number of government and private sector projects under development, and
- Further analysis considered justified in response to submissions received on the Draft ISP.

List of tables and figures

Tables

Figures

Glossary

This glossary has been prepared as a quick guide to help readers understand some of the terms used in the ISP. Words and phrases defined in the National Electricity Rules (NER) have the meaning given to them in the NER. This glossary is not a substitute for consulting the NER, the AER's Cost Benefit Analysis Guidelines, or AEMO's *ISP Methodology*.

Term	Acronym	Explanation
Actionable ISP project	-	Actionable ISP projects optimise benefits for consumers if progressed before the next ISP. A transmission project (or non-network option) identified as part of the ODP and having a delivery date within an actionable window. For newly actionable ISP projects, the actionable window is two years, meaning it is within the window if the project is needed within two years of its earliest in-service date. The window is longer for projects that have previously been actionable. Project proponents are required to begin newly actionable ISP projects with the release of a final ISP, including commencing a RIT-T.
Actionable New South Wales project and actionable Queensland project	-	A transmission project (or non-network option) that optimises benefits for consumers if progressed before the next ISP, is identified as part of the ODP, and is supported by or committed to in New South Wales Government or Queensland Government policy and/or prospective or current legislation.
Anticipated project	-	A generation, storage or transmission project that is in the process of meeting at least three of the five commitment criteria (planning, construction, land, contracts, finance), in accordance with the AER's Cost Benefit Analysis Guidelines. Anticipated projects are included in all ISP scenarios.
Candidate development path	CDP	A collection of development paths which share a set of potential actionable projects. Within the collection, potential future ISP projects are allowed to vary across scenarios between the development paths. Candidate development paths have been shortlisted for selection as the ODP and are evaluated in detail to determine the ODP, in accordance with the ISP Methodology.
Capacity	-	The maximum rating of a generating or storage unit (or set of generating units), or transmission line, typically expressed in megawatts (MW). For example, a solar farm may have a nominal capacity of 400 MW.
Committed project	-	A generation, storage or transmission project that has fully met all five commitment criteria (planning, construction, land, contracts, finance), in accordance with the AER's Cost Benefit Analysis Guidelines. Committed projects are included in all ISP scenarios.
Consumer energy resources	CER	Generation or storage assets owned by consumers and installed behind-the-meter. These can include rooftop solar, batteries and electric vehicles. CER may include demand flexibility.
Consumption	-	The electrical energy used over a period of time (for example a day or year). This quantity is typically expressed in megawatt-hours (MWh) or its multiples. Various definitions for consumption apply, depending on where it is measured. For example, underlying consumption means consumption being supplied by both CER and the electricity grid.

Term	Acronym	Explanation
Cost-benefit analysis	CBA	A comparison of the quantified costs and benefits of a particular project (or suite of projects) in monetary terms. For the ISP, a cost-benefit analysis is conducted in accordance with the AER's Cost Benefit Analysis Guidelines.
Counterfactual development path	-	The counterfactual development path represents a future without major transmission augmentation. AEMO compares candidate development paths against the counterfactual to calculate the economic benefits of transmission.
Demand	-	The amount of electrical power consumed at a point in time. This quantity is typically expressed in megawatts (MW) or its multiples. Various definitions for demand, depending on where it is measured. For example, underlying demand means demand supplied by both CER and the electricity grid.
Demand-side participation	DSP	The capability of consumers to reduce their demand during periods of high wholesale electricity prices or when reliability issues emerge. This can occur through voluntarily reducing demand, or generating electricity.
Development path	DP	A set of projects (actionable projects, future projects and ISP development opportunities) in an ISP that together address power system needs.
Dispatchable capacity	-	The total amount of generation that can be turned on or off, without being dependent on the weather. Dispatchable capacity is required to provide firming during periods of low variable renewable energy output in the NEM.
Distributed solar / distributed PV	-	Solar photovoltaic (PV) generation assets that are not centrally controlled by AEMO dispatch. Examples include residential and business rooftop PV as well as larger commercial or industrial "non-scheduled" PV systems.
Firming	-	Grid-connected assets that can provide dispatchable capacity when variable renewable energy generation is limited by weather, for example storage (pumped-hydro and batteries) and gas-powered generation.
Future ISP project	-	A transmission project (or non-network option) that addresses an identified need in the ISP, that is part of the ODP, and is forecast to be actionable in the future.
Identified need	-	The objective a TNSP seeks to achieve by investing in the network in accordance with the NER or an ISP. In the context of the ISP, the identified need is the reason an investment in the network is required, and may be met by either a network or a non-network option.
ISP development opportunity	-	A development identified in the ISP that does not relate to a transmission project (or non-network option) and may include generation, storage, demand-side participation, or other developments such as distribution network projects.
Net market benefits	-	The present value of total market benefits associated with a project (or a group of projects), less its total cost, calculated in accordance with the AER's Cost Benefit Analysis Guidelines.
Non-network option	-	A means by which an identified need can be fully or partly addressed, that is not a network option. A network option means a solution such as transmission lines or substations which are undertaken by a Network Service Provider using regulated expenditure.
Optimal development path	ODP	The development path identified in the ISP as optimal and robust to future states of the world. The ODP contains actionable projects, future ISP projects and ISP development opportunities, and optimises costs and benefits of various options across a range of future ISP scenarios.

Term	Acronym	Explanation
Regulatory Investment Test for Transmission	RIT-T	The RIT-T is a cost benefit analysis test that TNSPs must apply to prescribed regulated investments in their network. The purpose of the RIT-T is to identify the credible network or non-network options to address the identified network need that maximise net market benefits to the NEM. RIT-Ts are required for some but not all transmission investments.
Reliable (power system)	-	The ability of the power system to supply adequate power to satisfy consumer demand, allowing for credible generation and transmission network contingencies.
Renewable energy	-	For the purposes of the ISP, the following technologies are referred to under the grouping of renewable energy: “solar, wind, biomass, hydro, and hydrogen turbines”. Variable renewable energy is a subset of this group, explained below.
Renewable energy zone	REZ	An area identified in the ISP as high-quality resource areas where clusters of large-scale renewable energy projects can be developed using economies of scale.
Renewable drought	-	A prolonged period of very low levels of variable renewable output, typically associated with dark and still conditions that limit production from both solar and wind generators.
Scenario	-	A possible future of how the NEM may develop to meet a set of conditions that influence consumer demand, economic activity, decarbonisation, and other parameters. For the 2024 ISP, AEMO has considered three scenarios: *Progressive Change*, *Step Change* and *Green Energy Exports*.
Secure (power system)	-	The system is secure if it is operating within defined technical limits and is able to be returned to within those limits after a major power system element is disconnected (such as a generator or a major transmission network element).
Sensitivity analysis	-	Analysis undertaken to determine how modelling outcomes change if an input assumption (or a collection of related input assumptions) is changed.
Spilled energy	-	Energy from variable renewable energy resources that could be generated but is unable to be delivered. Transmission curtailment results in spilled energy when generation is constrained due to operational limits, and economic spill occurs when generation reduces output due to market price.
Transmission network service provider	TNSP	A business responsible for owning, controlling or operating a transmission network.
Utility-scale or utility		For the purposes of the ISP, ‘utility-scale’ and ‘utility’ refers to technologies connected to the high-voltage power system rather than behind the meter at a business or residence.
Virtual power plant	VPP	An aggregation of resources coordinated to deliver services for power system operations and electricity markets. For the ISP, VPPs enable coordinated control of CER, including batteries and electric vehicles.
Variable renewable energy	VRE	Renewable resources whose generation output can vary greatly in short time periods due to changing weather conditions, such as solar and wind.

Supporting documents

All documents comprising or supporting the Draft 2024 ISP are available on AEMO's website[40].

Appendices to the Draft 2024 *Integrated System Plan*

- Appendix 1 – Stakeholder Engagement
- Appendix 2 – Generation and Storage Opportunities
- Appendix 3 – Renewable Energy Zones
- Appendix 4 – System operability
- Appendix 5 – Network Investments
- Appendix 6 – Cost Benefit Analysis
- Appendix 7 – System Security
- Appendix 8 – Social Licence

Supporting documents

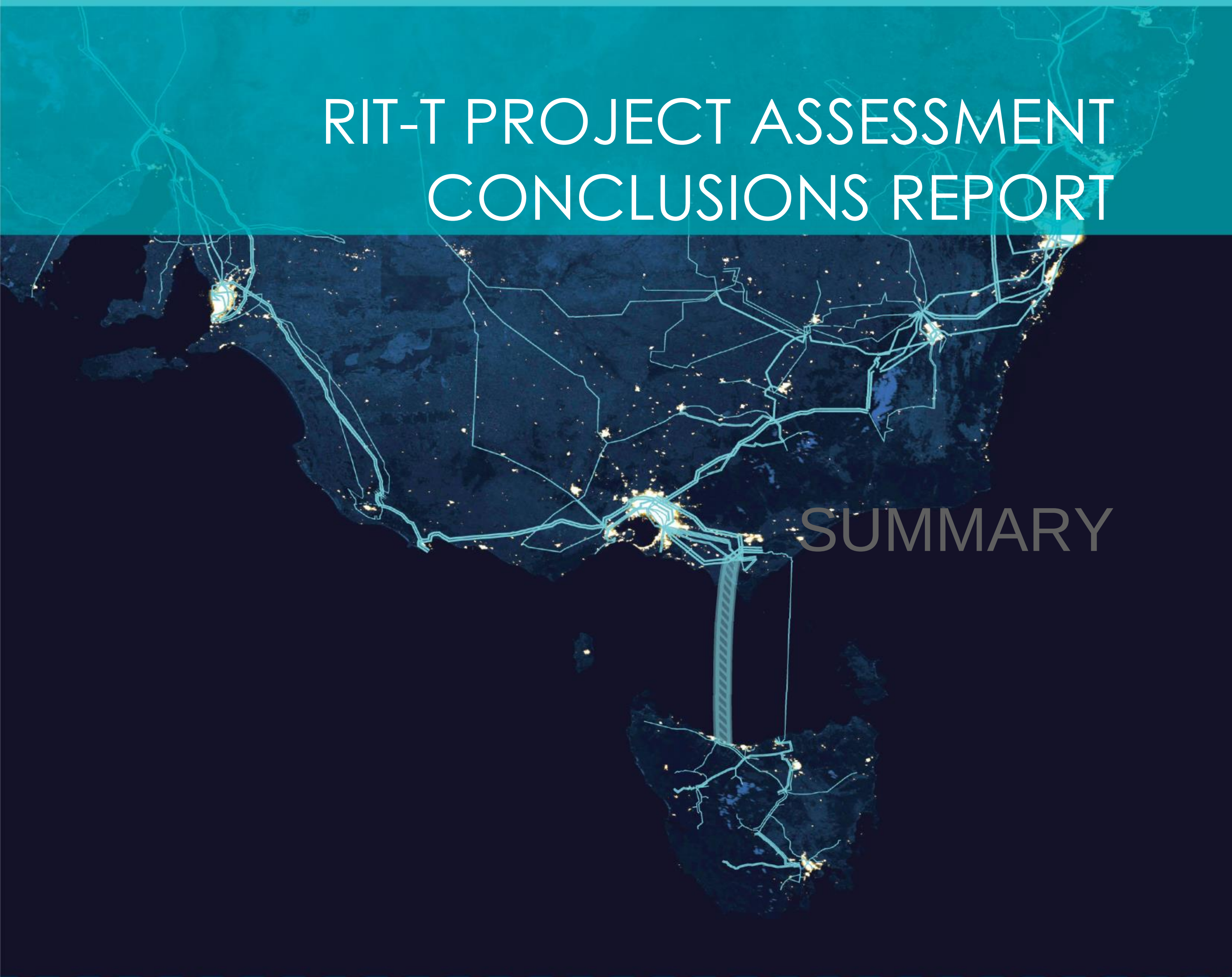
- Draft 2024 *Integrated System Plan* – overview
- Draft 2024 ISP chart data
- Draft 2024 ISP generation and storage outlook
- Draft 2024 ISP Inputs and Assumptions workbook, including the latest input data used for the Draft 2024 ISP modelling.
- Draft 2024 ISP traces
- Summary of consumer risk preferences project
  - Attachment 1 Deloitte report consumer risk preferences
  - Attachment 2 Antenna report consumer risk preferences

Regulatory publications

- *Addendum to the 2023 Inputs Assumptions and Scenarios Report*
- *Update to 2022 Integrated System Plan*

[40] At https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp.

RIT-T PROJECT ASSESSMENT CONCLUSIONS REPORT



SUMMARY

This document has been produced by Tasmanian Networks Pty Ltd, ABN 24 167 357 299 (hereafter referred to as "TasNetworks").

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Table of Contents

1. Introduction

Electricity markets around the world are changing rapidly as economies decarbonise in response to global warming and technological change. In Australia, the rapid growth in renewable generation and distributed energy resources (**DER**), combined with the closure of coal plant, are creating significant challenges for market participants, network companies, and customers.

The pace of change appears to be accelerating. Previously held preconceptions regarding the limitations of renewable generation to meet our future energy needs are being challenged, as Renewable Energy Zones (**REZs**) and large scale storage projects obtain support from investors and state government policies. The rapid pace of change is driving the need for network investment to accommodate radically different generation and load flows across the NEM.

In its role as the national transmission planner, the Australian Energy Market Operator (**AEMO**) is responsible for publishing an Integrated System Plan (**ISP**). The purpose of the ISP is to coordinate transmission and generation planning to provide for the efficient development of the power system over a planning horizon of at least 20 years. The ISP is a whole-of-system plan that reflects the long-term interests of electricity customers by meeting their needs at the lowest total cost.

In the 2020 ISP, AEMO identified ‘actionable ISP projects’. These projects are major transmission investments (or non-network options)[1] that are required to address an identified need and which form part of AEMO’s optimal development path. In other words, actionable ISP projects are needed to deliver the lowest cost solution that meets customers’ electricity needs. In its 2020 ISP, AEMO identified Project Marinus as an actionable ISP project, as described below:[2]

> “Marinus Link is a multi-staged actionable ISP project to be completed from 2028-29, with early works recommended to start as soon as possible, and with further stages to proceed if their respective decision rules are satisfied.”[3]

This document provides a summary[4] of the Project Assessment Conclusions Report (**PACR**). The PACR tests AEMO’s findings in its 2020 ISP by completing the Regulatory Investment Test for transmission (**RIT-T**) in accordance with the new regulatory arrangements for actionable ISP projects, which were introduced in July 2020.

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1 In accordance with the definition of ‘actionable ISP project’ in the National Electricity Rules.

2 AEMO, *2020 Integrated System Plan*, July 2020, page 82.

3 *2020 Integrated System Plan collectively referred to the HVDC interconnector and North West Transmission Developments as Marinus Link*

4 In accordance with clause 5.16.4(w) of the National Electricity Rules.

Throughout this summary, 'Project Marinus' refers to the HVDC interconnector assets and the supporting transmission investment in Tasmania, which is the North West Transmission Developments. These investments together constitute the RIT-T project, which is the subject of the PACR.

2. Inputs, assumptions and scenarios for the market modelling

Our market benefit modelling for Project Marinus, conducted in accordance with the RIT-T, was undertaken principally by Ernst & Young, with GHD being engaged to model the costs of ancillary services. Ernst & Young's modelling approach is closely aligned with AEMO's ISP modelling, as it identifies the lowest cost combination of generation, storage, demand side response, and transmission developments, without any preference for particular types of investment solutions or technologies.

To identify the net economic benefit from Project Marinus, Ernst & Young's modelling examines the total costs of meeting customers' future electricity needs 'with' and 'without' Project Marinus, under the 5 scenarios that AEMO adopted for the 2020 ISP. For the PACR, we have ensured that our inputs and assumptions are aligned with AEMO's current views,[5] as required by the RIT-T.[6]

A key consideration in the ISP and our RIT-T is the treatment of government policy announcements, which include state-based renewable energy targets and, in some instances, contracting arrangements to support these targets. In Tasmania, the Tasmanian Renewable Energy Target (**TRET**) has now been legislated, meeting one of the three decision rules specified in the 2020 ISP related to progressing stage 1 of Project Marinus to an actionable status.

To ensure that our approach in the PACR is objective, we adopted AEMO's treatment of government policies as set out in its most recent draft Inputs, Assumptions and Scenarios Report (**IASR**). In taking this approach, we note that concerns that some stakeholders have raised in relation to achievement of the TRET[7] could

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5 Specifically, we have adopted most of the inputs and assumptions in AEMO's draft 2021 Inputs, Assumptions and Scenarios Report (Draft 2021 IASR). However, we have retained the 2020 ISP scenarios for the purpose of the PACR.

6 National Electricity Rules, clause 5.15A.3(b)(7)(iv).

7 For example, submissions made by Bob Brown Foundation and Tasmanian Renewable Energy Alliance (TREA) to the Project Marinus Supplementary Analysis Report.

equally be made in relation to other government policies, which may implicitly assume that particular transmission or generation projects proceed, or outcomes eventuate.

To provide stakeholders with an insight into the impact of state government policies on the economic case for Project Marinus, we have conducted sensitivity modelling to examine the effect of replacing state government policies with a NEM-wide emission target. This approach removes distortions that may arise from state government policies that promote projects in particular regions in preference to an optimal NEM-wide solution. This sensitivity analysis shows that Project Marinus would be economically efficient if a Commonwealth 'carbon budget'[8] were adopted and state based policies removed. The analysis should further reassure stakeholders that we have tested Project Marinus against a range of plausible inputs and assumptions in assessing the economic case for the project.

3. Listening to customers and stakeholders

Customer and stakeholder engagement is an important part of our process and we welcome the feedback we have received. The modelling and analysis undertaken for the PACR takes into account the feedback received from customers and stakeholders over the past three years.

TasNetworks received a total of 40 formal written submissions throughout this RIT-T process. We conducted a total of seven industry forums across three capital cities and held a webinar during the course of this RIT-T assessment. In addition, we held in excess of 50 targeted stakeholder briefings for those consumers and stakeholders who sought further clarification about the economic and technical aspects of the project.

We have extended our consultation process beyond the requirements of the RIT-T, including engagement on our Initial Feasibility Report, which we published in February 2019. The Initial Feasibility Report provided indicative information on the likely costs and benefits of Project Marinus. The feedback we received helped guide our modelling approach and input assumptions, which were reflected in our Project Assessment Draft Report (**PADR**), published in December 2019.

We welcome the significant level of engagement from stakeholders and the feedback received in relation to our PADR. We listened to the feedback from stakeholders that they wanted our analysis to be aligned with the 2020 ISP. To address this issue effectively, we decided to undertake further modelling and to publish the results in our Supplementary Analysis Report in November 2020. The Supplementary Analysis Report also

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8 The carbon budget represents a Representative Concentration Pathway (RCP) of 2.6. An RCP of 2.6 requires that carbon dioxide (CO_2) emissions start declining by 2020 and achieve a net zero status between 2080 and 2100. RCP 2.6 is likely to keep global temperature rises below 2°C by 2100. In comparison, an economy-wide net zero target by 2050 achieves the Paris Agreement's aspirational target to limit global warming to below 1.5 °C. This pathway is typically referred to as RCP 1.9.

responded to stakeholder feedback received on our PADR and adopted the 2020 ISP's updated scenarios, inputs and assumptions.

We also engaged with stakeholders and invited feedback on our Supplementary Analysis Report through a further round of consultation and submissions. By extending the engagement process, we provided stakeholders with an opportunity to review the updated modelling results prior to the publication of the PACR. In preparing the PACR, we have taken account of stakeholder feedback we received on our Supplementary Analysis Report, in addition to the feedback on our PADR. The feedback we have received has been invaluable in identifying specific issues and concerns that we have addressed in the PACR, particularly in the material presented in Chapters 8 and 9, and the accompanying appendices and attachments.

4. 1500 MW Project Marinus is the preferred option[9]

On the basis of the modelling undertaken for the PACR, a 1500 MW Project Marinus is the preferred option. This conclusion was reached following the assessment of four credible options for increased interconnection capacity between Tasmania and Victoria:

- **Option A**: A 600 MW symmetrical monopole HVDC interconnector, including associated AC transmission network augmentation and connection assets.
- **Option B**: A 750 MW symmetrical monopole HVDC interconnector, including associated AC transmission network augmentation and connection assets.
- **Option C**: A 1200 MW HVDC interconnector, comprising two 600 MW symmetrical monopole HVDC interconnectors, plus associated AC network upgrades.
- **Option D**: A 1500 MW HVDC interconnector, comprising two 750 MW symmetrical monopole HVDC interconnectors, plus associated AC network upgrades.

The cost-benefit analysis in the PACR shows that each credible option delivers a positive net economic benefit across every scenario. Furthermore, Option D delivers the highest net economic benefit compared to the other credible options. This conclusion is unchanged whether:

- An equal weighting is attributed to each scenario, as shown in the figure below; or

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[9] All values presented in this summary are 1 July 2020 real dollars unless stated otherwise. Net Present Value (NPV) outcomes are also discounted back to 1 July 2020 based on the Weighted Average Cost of Capital (WACC) of 4.8% for all scenarios, except Slow Change (WACC of 3.8%). The totals in the tables may not sum precisely due to rounding of the underlying values throughout the report.

- Whether a one-third Step change scenario, and two-third Central scenario weighting is adopted in accordance with the 2020 ISP, as shown in the figure and table below.

The results below are reported for the earliest commissioning dates of 2027[10] for the first 750 MW stage and 2029 for the second 750 MW stage. The question of optimal timing is addressed in the next section.

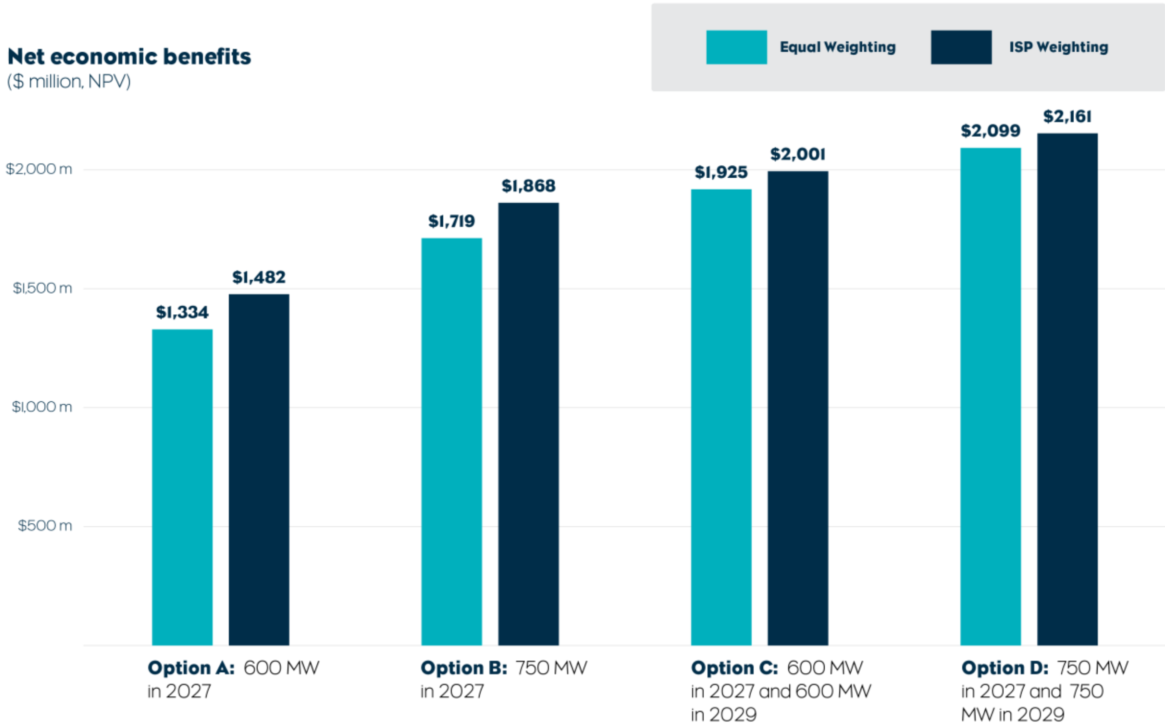

Figure 1: Net economic benefit for all credible options – ISP weighting and averaged across scenarios

[10] All dates in this summary are on a financial year basis. The year represents the start of the financial year. For instance, 2027 represents the financial year commencing from 1 July 2027 to 30 June 2028. Unless otherwise stated, all interconnector and capacity expansion occurs at the beginning of the financial year whereas unit retirements occur at the end of the financial year.

Table 1: Net economic benefit for each credible option, using ISP scenario weightings – Project Marinus timing of 2027 (link 1) and 2029 (link 2) ($ million, NPV)

Credible Options	Net economic benefit		
	Central Scenario	Step Change Scenario	2020 ISP weighting (67% - Central & 33% - Step Change)
600 MW	1,056	2,332	1,482
750 MW	1,367	2,870	1,868
1200 MW	1,353	3,297	2,001
1500 MW	1,416	3,650	2,161

In accordance with the RIT-T, the preferred option is a 1500 MW HVDC interconnector, comprising two 750 MW HVDC interconnector stages, plus associated AC network upgrades for each stage.

5. The pace of NEM transition and project timing

Since the commencement of the Project Marinus RIT-T in July 2018, the pace of NEM transition has been steadily increasing. Our modelling indicates that the pace of transition away from coal fired generation to variable renewable energy, supported by dispatchable storage and strategic interconnection, is likely to gather significant momentum this decade (Figure 2) with up to 6,500 MW of additional coal-fired power stations expected to retire by 2030, over and above the currently announced retirement schedule outlined in the 2021 Draft IASR.

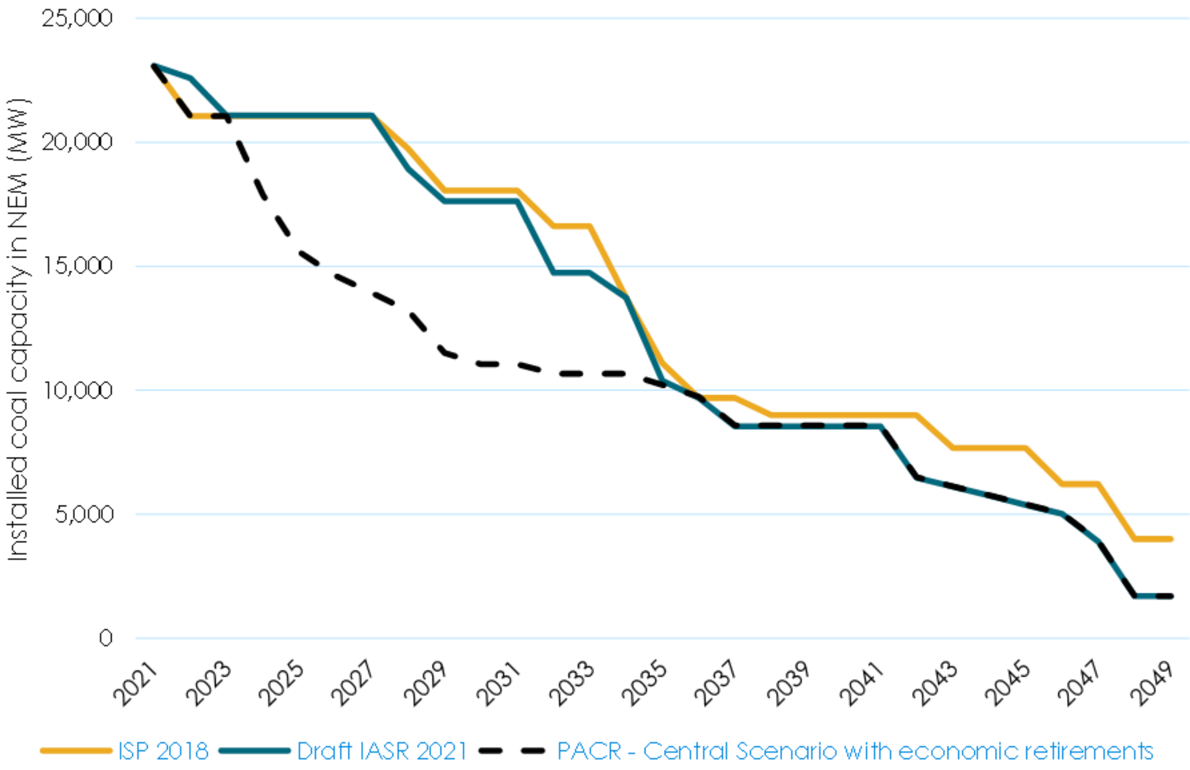

Figure 2: Pace of coal retirement from 2018 ISP, Draft IASR 2021 and Project Marinus PACR (Central scenario with economic retirements)

It is evident from recent company announcements that economic conditions are driving coal fired generation closures. In particular, since the publication of the Draft IASR 2021 in December 2020, the following announcements indicate the increasing pace of change in response to market conditions:

- In March 2021, Yallourn Power Station's (1,480 MW)[11] retirement was advanced by four years to 2028;
- In May 2021, Eraring Power Station (2,880 MW) announced that it would commence closure from 2030[12]. Origin Energy, the operators of Eraring, have indicated that the first of the four units will switch off two years earlier than previously planned; and
- In March 2021, AGL Energy undertook significant asset impairments and restructure plans, including indications that thermal generation units could be mothballed.[13]

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11 EnergyAustralia powers ahead with energy transition, Energy Australia, 10 March 2021.

12 NSW's Biggest coal plant, Origin's Eraring, starts closure from 2030, The Australian, 18 May 2021.

13 Slide 29, AGL Energy Investor Day, 30 March 2021.

In addition to these recent announcements, our assessment is that there is mounting evidence that the NEM's current trajectory is consistent with, or exceeding the Step Change scenario as outlined in the 2020 ISP. In particular, we note:

- Policy initiatives and legislation have been proposed or implemented by various state governments to advance renewable development to prepare for the retirement of the ageing thermal generation fleet. The objectives of these initiatives are aligned with, or exceed the Step Change scenario;
- The chair of the Energy Security Board has expressed views that the power system is already exceeding the Step Change scenario forecast in the Integrated System Plan (ISP) in 2020[14] and that the Step Change scenario could now be considered a conservative Central scenario given the ongoing pace of change[15];
- Increased generation from renewables is likely to exert increasing commercial pressure on coal fired generators as operational inefficiencies arise as output is continually varied to accommodate lower cost renewable generation in the supply stack;
- Sustained pressure from institutional investors and customers on the owners of coal-fired generators to align their business plans with the goals of the Paris Agreement could also lead to early retirement of assets due to environmental considerations.[16] Most recently this was highlighted by the owners of Loy Yang B power station when they flagged the challenges associated with refinancing debt for emission intensive generation assets[17];
- Recent announcements made by the Prime Minister and the Federal Treasurer regarding Australia's ambitions to reach net zero emissions as soon as possible, and preferably by 2050; and
- AEMO has indicated that one of its two Central scenarios for its 2022 ISP may reflect economy-wide net zero emissions by 2050.

In relation to project timing, our analysis confirms the findings in our PADR and Supplementary Analysis Report that the optimal timing of the preferred option depends on the future development of the NEM, which is subject to ongoing unprecedented change. In this context of NEM transition, Project Marinus has the potential to provide significant option value and ensure that wholesale power price increases owing to unexpected coal closure or unplanned maintenance is minimised. TasNetworks has considered the optimal timing based on the scenarios in the 2020 ISP, noting these scenarios are subject to change as AEMO prepares its 2022 ISP.

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14 Post 2025 options paper, ESB, 30 April 2021

15 ESB's Kerry Schott at Energy and Investment Conference, Sydney 24 March 2021

16 The inputs and assumptions in the Step Change scenarios best capture the electricity market outcomes required to achieve the targets of the Paris climate change agreement.

17 Alinta calls for Canberra to step in as banks retreat, The Sydney Morning Herald, 11 June 2021

At this stage, it is appropriate to describe the optimal timing for Stage 1 and Stage 2 of the preferred option as falling within a window, as shown in the table below.

Table 2: Optimal timing window for commissioning 1500 MW Project Marinus

Stage (750 MW each)	Optimal commissioning range across scenarios
Link 1	Between 2027 and 2031
Link 2	Between 2029 and 2034

We note that the new National Electricity Rules (Rules)[18] and accompanying guidelines[19] cater for this type of variability in the optimal project timing for a multi-staged actionable ISP project such as Project Marinus. In particular, AEMO may establish 'decision rules' in its ISP to guide optimal project timing. In addition, the Rules provide for a 'feedback loop' to verify that the project proponent's preferred option accords with AEMO's optimal development path.

In most instances, the lead time to withdraw dispatchable capacity from the NEM is much shorter than the timeframe for delivering large transmission projects. Given this observation, and the rapid pace of change in the generation sector, there is a compelling case to proceed on the basis that Project Marinus may be required at the earliest commissioning timeline of 2027 for Stage 1 and 2029 for Stage 2. Nevertheless, AEMO's 2022 ISP will be an important milestone in the context of Project Marinus to determine the optimal timing of the project in light of the latest available information and updated scenarios.

We also note that the significant benefits that Project Marinus will provide to the NEM have been recognised by the Australian and the Tasmanian governments through the execution of the Bilateral Energy and Emissions Reduction Agreement Memorandum of Understanding (**MOU**). This MOU provides funding of Project Marinus through the design and approvals phase to a final investment decision.

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18 Clause 5.16A.

19 AER, Cost benefit analysis guidelines: Guidelines to make the Integrated System Plan actionable, August 2020.

In relation to project timing, TasNetworks will proceed with the early works required for Project Marinus to be able to achieve a final investment decision in 2023-24 and subsequent commissioning of Stage 1 from as early as 2027 and Stage 2 by 2029. The actual timing of each stage will be determined by the 2022 and subsequent ISPs and AEMO's assessment of the proposed project in accordance with the feedback loop (as required by clause 5.16A.5(b) of the Rules) and its optimal development path at that time.

6. Project cost estimates

We recognise the concerns raised by stakeholders that the costs of major infrastructure projects can increase substantially from initial estimates. To address these concerns, we engaged engineering consultants, Jacobs, to conduct an independent review of our project cost estimates. Jacobs' report is provided as an attachment to the PACR and should provide stakeholders with confidence that our project cost estimates reflect the best available information and assessment at this time. The expected project cost estimate is sourced from the Jacobs report, with the figure calculated on the basis of expected cost of the option under a range of different reasonable cost assumptions.[20]

The Jacobs cost review was conducted on a probabilistic estimation basis that identifies each of the significant cost components, determines the likely range based on prior projects and associated probability distribution of each component and undertakes a sampling process to generate a probability distribution of project costs. The Association for the Advancement of Cost Engineering (AACE) recommends utilising the probabilistic estimation basis for all projects over $200 million in value.

Each possible outcome value of the total project cost can be given a P value which indicates its likelihood of occurrence. For instance, a P10 cost is the project cost with sufficient contingency to provide 10 per cent likelihood that this cost would not be exceeded. A P90 cost is the project cost with sufficient contingency to provide 90 per cent likelihood that this cost would not be exceeded. The contingency included in the expected project cost is the median output from a probabilistic analysis of possible outcomes.

The Jacobs report provides an expected project cost for the delivery of Project Marinus of $3,481 million ($2020).[21] This estimate is inclusive of contingency allowance based on a median probabilistic scenario.[22] The

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20 Uncertainty regarding costs, RIT-T application guidelines, August 2020

21 The Jacobs cost estimate is in June 2021 dollars. The modelling undertaken for this PACR is in $2020. Therefore, the Jacobs cost estimate was de-escalated by 1.11 per cent to account for inflation (March 2020 – March 2021, Australian Bureau of Statistics), addition of interest during construction charge and subtraction of $50 million in grant funding received by TasNetworks.

22 Refer to Project Marinus Cost Estimate Report prepared by Jacobs, released as Attachment 3 with this report.

report also provides an overall range for the total project estimate of $3.1 billion to $3.8 billion ($2020). This range is based on P10 and P90 views of the total project contingency allowance. Our sensitivity analysis confirms that the preferred option is expected to deliver a strongly positive net economic benefit, even if the upper cost range estimated by Jacobs eventuates.

Figure 3 shows a comparison of the likely range of costs assumed at the PADR stage, in the 2020 ISP and now, at the PACR stage. The cost estimate for the PADR was based on a "neat" estimate ($2.8 billion, $2020), which excluded accuracy/growth allowances and contingencies, whereas the cost estimate for the 2020 ISP included an accuracy allowance (commonly referred to as the "base estimate"). The 2020 ISP subsequently applied a 30 per cent deterministic contingency on the base estimate of $3.2 billion ($2020).

It can be seen that whilst the underlying cost estimate (i.e. the "neat" estimate before allowances and contingencies) has increased by 10 per cent since the PADR, the contingency amount has reduced such that the expected total project cost is comparable to the PADR. This is explained by the more advanced status of the scope definition, engineering, route alignment and other matters, leading to more certainty.

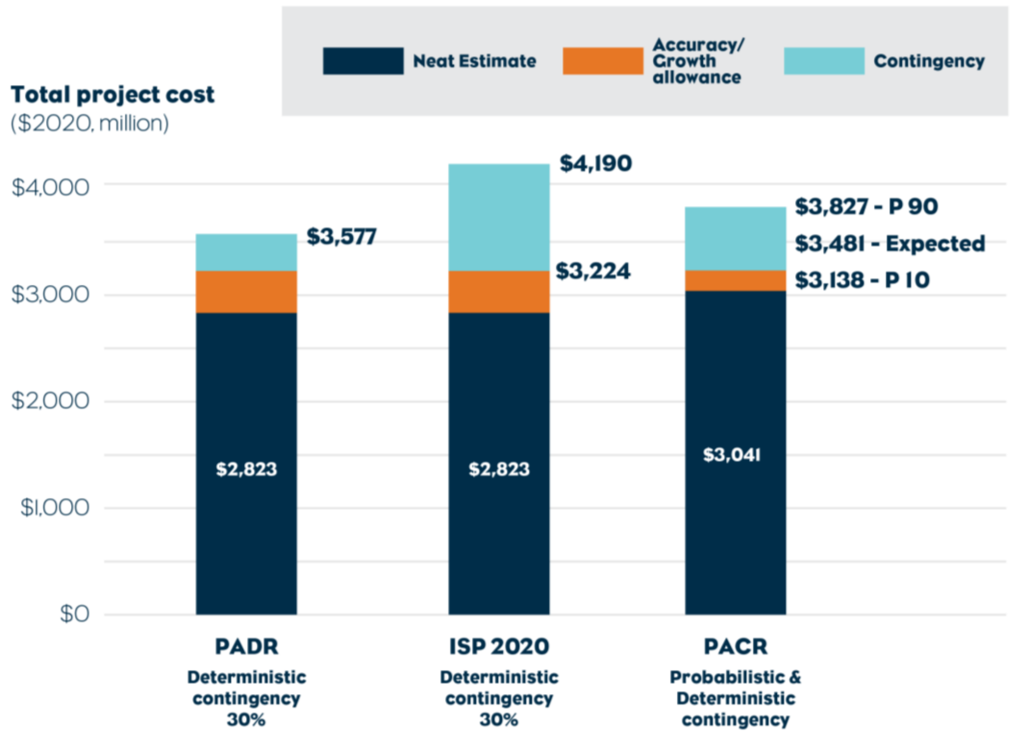

Figure 3: Range of total project cost outcomes comparison ($ million)[23]

[23] The PADR and ISP costs have been escalated from their original 2019 basis to 2020 prices. Inflation rate of 2.2% based on ABS data for March 2019 to March 2020.

If Project Marinus is completed in two stages spaced no more than 2 to 3 years apart, $600 million in total project cost savings can be achieved compared to two standalone 750 MW links. The savings are derived from streamlining environmental approvals, civil works, horizontal direct drilling and procuring volume discounts from suppliers for cable and converter stations. In addition to ensuring that our project cost estimates are robust, we have developed competitive tendering and procurement processes that are designed to obtain the best value for money from our contractors and equipment suppliers to achieve the lowest total cost of construction. Our robust project governance arrangements will also ensure that project costs are subject to ongoing management and review.

7. How does Project Marinus deliver benefits?

It is evident from the feedback we have received from stakeholders that our PACR should go beyond the requirements of the RIT-T to explain the sources of benefits that Project Marinus would unlock. As part of this explanation, stakeholders specifically want to understand why Project Marinus is preferred to solely increasing battery capacity on the mainland and how Project Marinus interacts with the various policy and project announcements in other NEM regions.

In broad terms, Stage 1 of Project Marinus enables customers in the NEM to benefit from cost-effective wind resources, together with the spare capacity that already exists in Tasmania's hydro system. Stage 2 is expected to be in service at least two years after Stage 1, at which time our modelling shows that Australian mainland NEM regions would otherwise require additional peaking gas-fired generation and/or storage. By staging Project Marinus, investment in lower cost storage capacity and wind generation in Tasmania will provide savings to the mainland NEM by displacing more expensive alternatives.

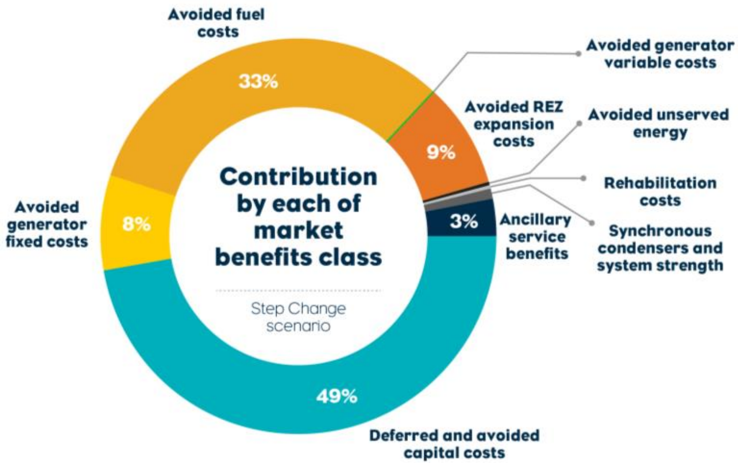

Figure 4: Market benefits provided by Project Marinus, Step Change scenario, 2027 and 2029[24]

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24 Data values for market benefit classes with minimal contribution have not been displayed but included in the analysis.

Our findings indicate that strategic transmission investment and long-duration energy storage have a key role to play in addressing the risk associated with 'drought' in Variable Renewable Energy (**VRE**). Our analysis also indicates that the benefits of interconnection are underestimated, owing to the computationally intensive nature of system analysis, such that that high-level, simplifying assumptions are made to support timely and cost-effective modelling. This means that the complexity of the NEM is understated, including through conducting system studies based on expected outcomes and perfect foresight, undertaking analysis at hourly granularity and utilising separate models for capacity expansion and long-term energy assessment. As explained in the PACR, these simplifications understate the benefits of interconnection and deep storage to manage variability and VRE drought.

8. Pricing impact

TasNetworks has received extensive feedback from customers regarding the transmission network pricing impact of Project Marinus, particularly in Tasmania. In principle, the most equitable and efficient pricing arrangement would allocate the costs of Project Marinus in a manner that reflects the beneficiaries. In practice, however, the beneficiaries cannot be determined precisely and will likely change over time. As a consequence, a pragmatic way forward needs to be developed.

To progress the discussion, TasNetworks has commissioned analysis by internationally respected consultants, FTI Consulting (FTI), to examine how customers in different NEM regions will benefit if Project Marinus proceeds. FTI's analysis demonstrates the following:

- Project Marinus can exert downward pressure on electricity prices across the NEM;
- Project Marinus provides significant benefits to the end-customer;
- The current pricing framework is not consistent with the 'beneficiaries pay' principle; i.e. the principle that end-customers should pay according to the benefits they receive; and
- All customers are better off if Project Marinus proceeds and costs are shared fairly across the NEM.

The ability of Project Marinus to exert downward pressure on power prices in regions not physically connected by the interconnector may not be intuitive to some readers. However, the interconnected nature of NEM and the ability of an asset to exert pricing impacts across all regions was highlighted by the recent event in Queensland with the unexpected outage at the Callide power station.[25] This incident led to a doubling of wholesale energy prices compared to the previous year across most of the NEM[26] as the finely balanced

[25] Update on incident at Callide power station, CS Energy, 25 May 2021

[26] Callide outage feeds power price surge, Australian Financial Review, June 2021

supply and demand balance was disrupted. Similar to a power station outage impacting the wholesale energy prices across all jurisdictions, Project Marinus has the ability to put downward pressure on energy prices by introducing additional dispatchable capacity and bringing further diversity to the VRE portfolio in the NEM.

The pricing issue is being progressed by the National Cabinet Energy Reform Committee, building on work undertaken by the Energy Security Board (ESB) and the Australian Energy Market Commission (AEMC). We are continuing to work with the Commonwealth and state governments to deliver a fair pricing outcome.

9. Next Steps

The publication of the PACR concludes the RIT-T process. From a regulatory perspective, the next stage of the process is to work with the Australian Energy Regulator (**AER**) and AEMO on the revenue setting arrangements for the project. These arrangements will need to address the two project components, Marinus Link (i.e. the HVDC interconnector) and the North West Transmission Developments. We will continue to consult with customers and stakeholders on these arrangements as further information becomes available and these processes commence.

AER Determination

Marinus Link Stage 1, Part A (Early works)

December 2023

Inquiries about this publication should be addressed to:

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AER reference: 23007165

Amendment record

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Final	19 December 2023	28

Executive Summary

The Australian Energy Regulator (AER) exists to ensure energy consumers are better off, now and in the future. Consumers are at the heart of our work, and we focus on ensuring a secure, reliable, and affordable energy future for Australia as it transitions to net zero emissions. The regulatory framework governing electricity transmission and distribution networks is the National Electricity Law and Rules (NEL and NER). Our work is guided by the National Electricity Objective as one of the National Energy Objectives (NEO).

Marinus Link is a proposed 1500MW transmission line between Tasmania and Victoria. The project comprises two undersea High Voltage Direct Current (HVDC) cables running across Bass Strait and converter stations in Tasmania and Victoria.

On 30 June 2022, the Australian Energy Market Operator (AEMO) published the 2022 Integrated System Plan (ISP) that identified significant new transmission requirements to connect renewable generation sources and firming capacity. One transmission project identified is Marinus Link, included in the 2022 ISP as an 'actionable project' under the optimal development path (ODP).[1] The ISP recommends commencing operation of cable one in 2029 and cable two in 2031. On 3 September 2023, Marinus Link shareholders announced the project will focus on delivering one cable in the first instance at an estimated cost of $3.0-3.3 billon, with negotiations to continue on a second cable.[2]

Marinus Link is a component of 'Project Marinus', which also includes the North West Transmission Development (NWTD) project progressed by TasNetworks. While both Marinus Link and the NWTD project are part of 'Project Marinus', this decision considers proposed early works expenditure for Marinus Link, as distinct from the NWTD project.

On 1 June 2023, we published our decision to commence a revenue determination process for Marinus Link and the Commencement and Process Paper to apply to the determination.[3] This decision was made in accordance with Rule 6A.9 of the NER that provides for an 'Intending Transmission Network Service Provider' (Intending TNSP) to request us to commence the process for making a transmission determination for a proposed prescribed transmission service, and to determine the process to apply for making that transmission determination.

The Commencement and Process Paper sets out a staged approach comprising:

- Stage 1, Part A (Early works): a revenue determination for pre-construction activities allowing for better revealed construction costs and stakeholder engagement.
- Stage 1, Part B (Construction costs): a construction cost determination, in which we would determine the cost of constructing Marinus Link.

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1 AEMO, *2022 Integrated System Plan*, June 2022, p. 61.

2 The Hon Chris Bowen MP, The Hon Julie Collins MP, The Hon Jeremy Rockliff MP, and the Hon Guy Barnett MP, *Investing in the future of Tasmanian energy with Marinus Link* [joint media release], Commonwealth and Tasmanian Governments, 3 September 2023, accessed 14 November 2023.

3 AER, *Marinus Link Decision: Transmission Determination Commencement and Process Paper,* June 2023.

- Stage 2: a full revenue determination, which, on the basis of the construction cost determination, we would determine all of the matters we are required to under rule 6A.14 of the NER.

The Commencement and Process Paper sets out the decisions to be made under rule 6A.14 of the NER at each stage of the process. The scope of the Stage 1, Part A (Early works) revenue determination is substantially narrower than a standard determination process with key decisions including review of the efficiency and prudency of proposed capital expenditure for early works, the allowed rate of return, and application of incentive schemes.

Stage 1 is a pre-commissioning stage where prescribed transmission services are not provided, and revenues are not recovered from consumers. Costs in Stage 1 are to be rolled into the Regulatory Asset Base (RAB), to be determined in Stage 2. Consistent with the staged approach, the first regulatory control period will commence on 1 July 2025, with the second regulatory control period to commence at Stage 2.

Prior to constructing the Marinus Link interconnector, Marinus Link is undertaking early works to:[4]

- improve the accuracy of forecast construction costs; and
- reduce the risks of project delays.

Marinus Link plan to make a final investment decision on the project in December 2024, with early works critical to informing this decision.

The proposed forecast prudent and efficient capital expenditure (capex) required to deliver early works is $196.5 million ($2022-23).[5]

Marinus Link *Stage 1, Part A (Early works) – scope of works*

We consider the scope of works proposed by Marinus Link are consistent with the Australian Energy Market Commission's (AEMC) definition of early works.[6] In adopting a staged approach to delivering large transmission projects, the early works component allows for the resourcing of design and planning, quantification of project risks and the building of social licence. Marinus Link's scope of works includes technical design and specifications, project management, environmental impact assessments, community and land owner engagement and procurement strategy and execution. We consider these works critical to improving the accuracy of cost estimates and delivering the project in accordance with AEMO's 2022 ISP.

The forecast costs of undertaking Stage 1 Part A (Early works) are efficient and prudent

The forecast costs that are reasonably required to deliver the project will be rolled into the RAB and will be recovered from consumers once Marinus Link commences providing prescribed transmission services.

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4 Marinus Link, *Marinus Link - Revenue proposal - Stage 1 part A early works - 31 July 2023*, 31 July 2023, p.28.

5 Marinus Link, *Marinus Link – Revenue proposal – Stage 1 part A early works – 31 July 2023*, 31 July 2023, p.5.

6 AEMC, *Stage 2 Final Report*, 27 October 2022, p. 41. Refer to section 2 for the full definition.

Marinus Link proposed $196.5 million ($2022-23) in forecast capex for early works.[7] We have examined Marinus Link's proposed capex forecast and our view is that the amount proposed is reasonable, prudent and efficient to deliver early works for the Marinus Link project. We accept Marinus Link's forecast.

In particular, we consider that:

- as noted above, the scope of Marinus Link's capex is consistent with the AEMC's definition of early works
- the majority of expenditure is on acquiring expert services and advice from external sources – we consider Marinus Link's procurement procedures are appropriate to deliver efficient procurement outcomes
- the proposed staff costs are in line with cost expectations based on analysis of Australian Bureau of Statistics (ABS) data
- overheads are slightly higher than, but still in line with, projects of a similar scale – we consider this is explained by the cost of establishing and operating a single asset network, versus the multi-asset network of the other ISP projects.

Incentive schemes, cost pass throughs and rate of return

Pursuant to the process established in the Commencement and Process Paper, key decisions for the Stage 1, Part A (Early works) include the application of incentive schemes, cost pass throughs and the rate of return (ROR). Our decisions on these matters are as follows:

- Our preference at this stage is to apply the capital expenditure sharing scheme (CESS). However, the decision on whether the CESS will apply is to be deferred until we know more about the full costs and risks of the project, following submission of the Stage 1, Part B (Construction costs) proposal. The demand management innovation allowance mechanism (DMIAM) and the small-scale incentive scheme (SISS) will not apply to Stage 1, Part A (Early works). Section three discusses incentive schemes.
- We accept the additional pass through events as proposed by Marinus Link and will set materiality threshold for cost pass throughs based on Marinus Link's calculation of the maximum allowed revenue for each regulatory year. Approved cost pass throughs will be recovered by adding them to the RAB until Marinus Link commences providing prescribed services. Section four discusses cost pass throughs.
- We will apply the AER's 2022 Rate of Return Instrument to set Marinus Link's ROR, noting Marinus Link proposed using TasNetworks' ROR. We note in suggesting the application of TasNetworks' ROR, Marinus Link were not seeking to bypass the application of the Rate of Return Instrument, but rather proposed to apply the ROR that was calculated when the Rate of Return Instrument was applied to TasNetworks. Section five discusses ROR, including the reasoning for our decision.

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[7] Marinus Link, *Marinus Link – Revenue proposal – Stage 1 part A early works – 31 July 2023*, 31 July 2023, p.5.

Next steps

The capital expenditure we have approved in this determination will be rolled into Marinus Link's opening RAB value, to be established in Stage 2 plus or minus any adjustments allowed for by the NER.

The next stage of the project will be important in ensuring that Marinus Link determines the accurate cost of constructing the full project and obtains all necessary approvals to deliver the project on time. This will ensure that AEMO has all the necessary information when undertaking the ISP feedback loop, and the Stage 1, Part B (Construction cost) revenue proposal includes an accurate updated forecast for the costs reasonably required to construct the project.

We expect that Marius Link will have resolved outstanding issues relating to the implementation of the project by the completion of the Stage 1, Part A (Early works) process, including land costs, environmental impacts and biodiversity offsets and project design.

We also expect that Marinus Link demonstrate the benefits of its early works activities as part of its Stage 1, Part B (Construction cost) proposal, including through risk identification and mitigation and social licence.

Contents

1 Marinus Link actionable ISP project

Marinus Link is a proposed $3.8 billion[8] ($2022-23) interconnector between Tasmania and Victoria with a capacity of 1500MW and involves approximately 255 kilometres of undersea High Voltage Direct Current (HVDC) cable and approximately 90 kilometres of underground HVDC cable in Victoria. It also includes converter stations in Tasmania and Victoria.

Marinus Link is included in the AEMO 2022 ISP ODP as a 'staged actionable project'. The ISP considers four scenarios of future plausible market developments to capture uncertainty regarding the pace of energy transformation on the path to reach net zero by 2050.[9] Under the ISP, AEMO considers that the optimal timing for Marinus Link is a target delivery date of 2029-32, with early works delivered in two parts. AEMO released the 2024 draft ISP on 15 December 2023. While the final 2024 ISP will have implications for Project Marinus, including optimal timing for delivery, the Stage 1, Part A (Early works) is considered in the context of the 2022 ISP.

1.1 Marinus Link proposal

On 30 June 2022, the AEMO published the 2022 Integrated System Plan (2022 ISP).[10] The 2022 ISP identifies significant new transmission requirements to connect new renewable generation sources as well as firming capacity. One transmission project identified is Marinus Link. The ISP recommends commencing operation of cable one in 2029 and cable two in 2031. To meet AEMO's recommended timeframes, Marinus Link advises that construction must commence in 2025.

Marinus Link plans to make a final investment decision on the project in December 2024 so that it can commence construction in 2025 and meet AEMO's timelines. To inform this investment decision, Marinus Link is seeking to understand the revenues it may recover were it to be regulated by a transmission determination made by us under the NER. To this end, Marinus Link has submitted that we should commence (and determine the process for) determining a transmission determination that would apply to it. In support, Marinus Link submits:

- the Marinus Link project is an 'actionable ISP project'
- the project has been subject to investment analysis and a regulatory investment test for transmission (RIT-T) process
- the Victorian, Tasmanian and Commonwealth government have provided support for the project
- Marinus Link has been registered as an Intending TNSP by AEMO.

1.2 Rule requirements

Rule 6A.9 of the NER provides for an 'Intending TNSP' to request us to commence the

8 AEMO, *2022 Integrated System Plan*, 30 June 2022, p. 67. We note estimated construction costs have increased since publication of the 2022 ISP.

9 AEMO, *2022 Integrated System Plan*, June 2022, p. 25.

10 AEMO, *2022 Integrated System Plan,* June 2022.

process for making a transmission determination for a proposed prescribed transmission service, and to determine the process to apply for making that transmission determination.[11]

An 'Intending TNSP' is defined as:[12]

> …
>
> (a) an *Intending Participant* who intends to provide *prescribed transmission services* by means of its *proposed transmission system*; or
>
> (b) a *Market Network Service Provider* who intends to provide *prescribed transmission services* by means of its converting transmission system,
>
> and … includes that person once registered as a *Network Service Provider* for the provision of *prescribed transmission services* by means of its *transmission system*.

A 'proposed prescribed transmission service' is defined as:[13]

> …
>
> *prescribed transmission services* to be provided by means of:
>
> (a) a proposed *transmission system*; or
>
> (b) a converting transmission system.

Further, an 'Intending Participant' is defined as '[a] person who is registered by [the Australian Energy Market Operator] as an Intending Participant under Chapter 2 [of the NER]'. [14]

If an Intending TNSP then requests us to commence the process for making a transmission determination for a proposed prescribed transmission service, the NER affords us broad discretion in determining that request. Relevantly, clause 6A.9.2(e) of the NER provides:

> In determining whether to commence the process for making a *transmission determination* requested by an Intending TNSP under [clause 6A.9.2(a)] the AER may have regard to any matters it considers appropriate, including:
>
> (1) whether the Intending TNSP intends to deliver an *actionable ISP project* or a project that is not an *actionable ISP project* but has been subject to the *regulatory investment test for transmission*;
>
> (2) the likelihood of the Intending TNSP delivering that project; and
>
> (3) in the case of a converting transmission system, the Intending TNSP's application to the AER to determine the service to be a *prescribed transmission service*.

11 NER, cl. 6A.9.2.

12 NER, cl. 6A.9.1(b).

13 NER, cl. 6A.9.1(b).

14 NER, ch 10.

An 'actionable ISP project' is defined as:[14]

> A project:
>
> (a) that relates to a *transmission asset* or *non-network option* the purpose of which is to address an *identified need* specified in an *Integrated System Plan* and which forms part of an *optimal development path*; and
>
> (b) for which a *project assessment draft report* is required to be published in the *Integrated System Plan* that identifies that project.

Marinus Link delivers value on a scenario weighted basis.[15]

Marinus Link's Stage 1, Part A (Early works) of $196.5 million ($Nominal) in forecast capex is for the early works. Early works projects were introduced as part of the staging of large transmission projects. Our guidance note on the regulation of actionable ISP projects identified staging as a means to reduce the risks of actionable projects and increase flexibility to respond to changing market conditions.[16] Early works allows for investing time in the planning and design phase. It can help identify and quantify project risks, and enable innovative and cost effective design.[17]

Early works is a relatively recent addition to the regulatory framework. We consider early works projects is an evolving area. Where different cost types are proposed, we would be open to considering those to the extent that the early work would promote the long term interests of consumers. We are committed to being flexible within the regulatory framework and to assist the timely delivery of ISP projects, and we consider that early works should produce reliable cost estimates and expenditure forecasts for later project stages. We expect Marinus Link to provide information on how early works has assisted in the delivery of the multi-stage project.

15 Marinus Link, *Marinus Link - Revenue proposal - Stage 1 part A early works - 31 July 2023,* 31 July 2023, p. 3; AEMO, *2022 Integrated System Plan*, 30 June 2022, p. 73.

16 AER, *AER – Final - Guidance Note – Regulation of actionable ISP projects,* March 2021, p. 25.

17 AER, *AER – Final - Guidance Note – Regulation of actionable ISP projects,* March 2021, p. 26.

2 Prudent and efficient project expenditure

This section outlines our assessment of Marinus Link's proposed forecast capital expenditure (capex) for Marinus Link early works Stage 1, Part A. Marinus Link will not provide transmission services until Stage 2, during the second regulatory period as set out in the Commencement and Process Paper, and will not recover revenue from customers until that time. Consequently, all of Marinus Link's expenses are treated as capital expenditure that will be accrued in a regulatory asset base (RAB) until Marinus Link commences prescribed services.

2.1 Forecast capital expenditure

Marinus Link's proposal forecasts that Stage 1, Part A will require $196.5 million ($nominal) in capex.[18] Table sets out the proposed expenditure for early works.

Table 1 Proposed expenditure for early works activities ($m nominal)

Category	2021-22	2022-23	2023-24	6 months to 31 Dec 2024	Total
Landowner and community engagement programs, including Traditional Owners, and stakeholder relations	4.0	6.0	9.0	4.1	23.2
Land and easement acquisition	2.6	1.8	2.5	1.1	8.0
Environmental impact assessments	2.7	7.4	9.9	4.6	24.5
Technical designs and specifications	17.4	12.2	11.7	2.6	43.9
Procurement strategy and execution[5]	2.4	4.6	8.8	3.1	18.9
Program and project management	4.5	8.2	10.4	4.7	27.8
Corporate costs and support	6.6	13.9	21.0	8.7	50.2
Sub-total	**40.1**	**54.2**	**73.3**	**28.9**	**196.5**
Less Grant funding	-9.4	-27.2	-19.4	-11.6	-67.6
Net expenditure	**30.7**	**27.1**	**53.9**	**17.2**	**128.9**

Source: Marinus Link, *Marinus Link - Revenue proposal - Stage 1 part A early works - 31 July 2023*, 31 July 2023, pp.4-5.
Note: Numbers may not sum exactly due to rounding.

We have accepted Marinus Link's proposed forecast capex of $196.5 million for 2021-22 to 31 December 2024. Table 2 AER determination of forecast capex ($m nominal) sets out our

18 Marinus Link, *Marinus Link - Revenue proposal - Stage 1 part A early works - 31 July 2023,* 31 July 2023, p.5.

determination on the total capex required for the early works in each year of the regulatory control period.

Table 2 AER determination of forecast capex ($m nominal)

	2021-22	2022-23	2023-24	6 months to 31 Dec 2024	Total
Proposed capex	40.1	54.2	73.3	28.9	196.5
AER decision	40.1	54.2	73.3	28.9	196.5

Source: Marinus Link, *Marinus Link - Revenue proposal - Stage 1 part A early works - 31 July 2023,* 31 July 2023, p.5.
Note: Numbers may not add up due to rounding. Excludes equity raising costs.

Marinus Link has proposed $128.9 million (nominal) of capex for its early works activities after a deduction of grant funding of $67.6 million. Marinus Link included an independent review in support of this proposed expenditure in its proposal.[19] In assessing the proposal, we reviewed Marinus Link's initial submission, identified and issued several information requests to better understand the structure and cost of the proposal, met with Marinus Link to discuss the proposal, and took into account stakeholder views. On the basis of this review, we consider Marinus Link's early works expenditure is prudent and efficient.

Scope and prudency of the early works proposal

We consider the scope of works proposed by Marinus Link are consistent with the AEMC's definition of early works.

The AEMC defines early works as:[20]

> *Any activity which commences prior to the construction of the preferred option can be considered early works if the activity can be justified as being necessary to:*
>
> - *improve the accuracy of project cost estimates, and*
> - *ensure that a project will be delivered within the time frames specified by the most recent ISP.*

Such as:

> - *activities to build social licence, including works to provide community benefits,*
> - *completion of environmental approvals,*
> - *construction works to test engineering design, and purchasing easements and equipment.*

We are satisfied the proposed scope of works meets this criteria. The early works investments should enable it to mitigate cost, technical, social license and permitting risks, and to establish an organisation capable of delivering the project. The scope of works is also

19 Aurecon Australasia Pty Ltd, *Marinus Link - Attachment 02 - Aurecon report - 31 July 2023,* 31 July 2023.

20 AEMC, *Stage 2 Final Report*, 27 October 2022, p. 41.

consistent with the preferred option from the Project Assessment Conclusion Report (PACR).[21] Therefore we consider that the proposed scope of works are prudent.

Efficiency of the expenditure proposal

The second part of our assessment is to determine whether Marinus Link's proposed early works capex is efficient. To do this, we have reviewed the total proposed capex against similar ISP projects, and also assessed the efficiency of the component parts of the proposal.

Marinus Link's early works capex is approximately 5% of the total cost of the Marinus Link project.[22] This benchmarks well with other large transmission projects such as HumeLink and the Victoria to New South Wales Interconnector West (VNI West) .[23] We consider that on this top-down metric, Marinus Link's early works expenditure appears reasonable.

We also note that, at the time of the Stage 1, Part A (Early works) proposal, more than two thirds of early works capex has already been incurred.[24] Marinus Link incurred this expenditure without the added certainty of the regulatory process and the mechanisms it provides for cost recovery. We consider this has provided an additional incentive for Marinus Link to contain its early works costs to an efficient level.

We have evaluated Marinus Link's expenditure on direct costs, direct cost overheads, corporate overheads, as well its establishment costs and its various fees and charges. We have found that Marinus Link's capex benchmarks well with other large transmission projects, such as HumeLink and VNI West by category.

Direct costs

Marinus Link's early works does not include the installation of network assets, but rather, involves several establishment and design processes required to commence the project. The major component of Marinus Link's expenditure is to acquire expert advice and reports, and to engage staff and acquire facilities necessary to begin building network assets. Consequently, the majority of Marinus Link's direct costs are for goods and services acquired from external sources. Marinus Link, as a wholly owned subsidiary of TasNetworks, has utilised TasNetworks' tendering and procurement processes to acquire these services. We assessed TasNetworks' tendering and procurement processes during our revenue determination and we consider them to be prudent and efficient.[25] We consider they will also deliver prudent and efficient outcomes for Marinus Link.

The remaining component of direct cost relates to internal labour. In response to an information request around labour cost, Marinus Link noted:[26]

> *The majority of resources and skillsets required to develop the Marinus Link project are specialised with high global demand, especially for development of HVDC type assets.*

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21 TasNetworks, *PACR: Project Marinus*, 30 June 2021.

22 AER analysis. Marinus Link, *Revenue Proposal Stage 1– Part A (Early works),* 31 July 2023, p.5; AEMO, *2022 Integrated System Plan (ISP)*, 30 June 2022, p. 73.

23 AER analysis. AEMO*, Integrated System Plan Feedback Loop Notice – HumeLink (Early Works)*, 19 May 2023, p. 1; Transgrid, *A.1_VNI West Draft CPA-1_Principal Application_1 September 2023 Public,* September 2023.

24 AER analysis. This is expenditure before grant funding.

25 AER, *TasNetworks Electricity Transmission Draft Determination Attachment 5 Capital Expenditure.* September 2023, p.5.

26 Marinus Link, *Marinus Link – information request #003 – Labour and corporate costs, service provider costs, and other miscellaneous – 20230923 – Public*, 13 October 2023.

> …
>
> *While MLPL has its main office in Hobart, staff are based across Australia, including in all major capital cities, as well as New Zealand. To attract and retain staff, MLPL has had to remunerate key staff on market-based remuneration. We have experienced relatively high turnover that leads to new staff being paid commensurate with increased market rates.*

We accept that the labour component of Marinus Link's direct cost compares reasonably with benchmarks of the cost of labour for equivalent projects such as HumeLink and VNI West.[27] It also benchmarks well against the ABS Average Weekly Earnings for similarly skilled professional staff.[28]

Overheads attributed to direct cost

Direct Costs Overheads include several components which would generally be added to direct labour, such as building/office space, facilities, and training. We have benchmarked these costs as a percentage of direct costs against other TNSPs and consider them reasonable to support Marinus Link's direct costs.

Corporate Overhead

As an uplift on Direct Costs, we consider that Corporate Overheads benchmark well against VNI West and HumeLink's early works, considering that Marinus Link is a single project entity.

While the overhead proportion is at the upper end of benchmarks for Corporate Overheads, the uplift appears reasonable for a single project entity, as opposed to an interconnector built under a large umbrella TNSP (i.e., the cost of maintaining a company board, corporate IT system and other functions is spread over one project, rather than many projects). On this basis we consider that the corporate overhead cost is reasonable in the circumstances.

Establishment Costs

Marinus Link, as a new business and intending TNSP, faces costs of business establishment of around $15.9 million or 8.1% of its proposed early works capex. The Memorandum of Understanding between the Commonwealth and Tasmanian Governments requires Marinus Link to be structured as a separate entity with related necessary costs.[29] Consequently, it is not possible for TasNetworks to own and operate Marinus Link under its current transmission licence.

We note in a supporting document provided by Marinus Link, EY identified 269 corporate processes of which 139 or 52% were fully or partly reliant on TasNetworks and will be transitioned to Marinus Link.[30] We have assessed the material and agree that the activities are required to establish a business of this type, and are low relative to the cost of the project, such that any overstatement would not be material.

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[27] AER analysis. Transgrid, *A.5 - TransGrid - Labour and Overhead Costs for VNI - CONFIDENTIAL*, December 2020; Transgrid, *HumeLink Stage 1 (early works) - Regulatory models A.7 - Labour and Indirect Cost Model - CONFIDENTIAL*, April 2022.

[28] Australian Bureau of Statistics, *Average Weekly Earnings, Australia,* May 2023.

[29] Marinus Link, *Marinus Link - Revenue proposal - Stage 1 part A early works - 31 July 2023*, 31 July 2023, p. 11.

[30] Aurecon Australasia Pty Ltd, *Marinus Link - Attachment 02 - Aurecon report - 31 July 2023,* 31 July 2023, p. 48.

Conclusion on Early Works capital expenditure

We are satisfied that Marinus Link's Stage 1, Part A (Early works) capital expenditure is prudent and efficient. We accept Marinus Link's capex forecast.

3 Incentive Schemes

Pursuant to the process the AER has established in the Commencement and Process Paper, for Stage 1, Part A, we must make decisions on the following incentive schemes:

- the small-scale incentive scheme (SSIS);
- the demand management innovation allowance mechanism (DMIAM); and
- the capital expenditure sharing scheme (CESS).

Marinus Link submitted that the DMIAM and the SSIS should not apply to its early works expenditure. As the Marinus Link interconnector is neither operational nor providing services during early works, DMIAM cannot apply. As for the SSIS, Marinus Link notes that this scheme has only been applied to DNSPs.[31] We agree with Marinus Link that these schemes are not appropriate for an early works proposal before prescribed services commence. We agree the DMIAM and the SSIS do not to apply to Marinus Link, Stage 1, Part A.

Marinus Link proposes that the CESS should not apply to its Stage 1 Part A expenditure. Marinus Link contends applying the CESS would discourage risk-taking and increased expenditure that could benefit consumers in the long-term. Further, it contends that early works are especially prone to forecasting error, so over- or under-spending its approved capex estimate could be outside its control.[32]

Marinus Link notes that, should the CESS apply, and given it will not earn revenue until 2029, any resulting adjustment to its revenue would be need to capitalised and included in its opening RAB.[33] That is, an underspend would directly result in a lower RAB, but the CESS reward would increase the RAB, and vice versa for an overspend.

The main precedent regarding the application of CESS to the early works of large transmission projects is HumeLink.[34] We included HumeLink's capex forecast in Transgrid's CESS targets. However, we viewed it as too early to commit to the application of the CESS at an early works stage before seeing the full capex proposal, and suggested we would fully assess the application of the CESS at stage 2 when we know about the full costs and risks of the project.[35]

We note the AER has previously shown a preference to apply the CESS for large transmission projects. Although we have deferred the decision to HumeLink stage 2, our

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31 Marinus Link, *Marinus Link - Revenue proposal - Stage 1 part A early works - 31 July 2023*, 31 July 2023, pp. 46-49.

32 Marinus Link, *Marinus Link - Revenue proposal - Stage 1 part A early works - 31 July 2023*, 31 July 2023, pp. 47-48.

33 Marinus Link, *Marinus Link – information request #002 – Clarification of CESS time period – 20230922 – Public*, 28 September 2023; Marinus Link, *Marinus Link - Revenue proposal - Stage 1 part A early works - 31 July 2023*, 31 July 2023, p. 42.

34 There are distinctions. HumeLink was a single project contributing to Transgrid's CESS, while the Marinus Link project would be the entirety of Marius Link's CESS. Further, the determination for HumeLink (stage 1 part 1) was published before the revised CESS guidelines, which provides guidance for large transmission projects. HumeLink (stage 1 part 2) was published with the new CESS guidelines.

35 AER, *AER - Determination - HumeLink - August 2022*, August 2022, p. 10; AER, *AER - Determination - HumeLink Stage 1 (part 2) - August 2023*, August 2023, pp. 7, 12.

default position would be to apply the CESS to HumeLink.[36] We have applied the CESS to Project EnergyConnect.[37]

In deciding whether to apply the CESS to a large transmission project, we follow the updated CESS guideline. The CESS guideline states that our default position is to apply the CESS and we will be careful in making exclusions, taking into consideration:[38]

- *the TNSP's CESS and capital expenditure proposals*
- *benefits to consumers from the exemption*
- *the size of the project*
- *the degree of capital expenditure forecasting risk*
- *stakeholder views.*

We are not persuaded by Marinus Link's arguments to exclude early works expenditure from the CESS. As stated, Stage 1 Part A expenditure is largely actual (already incurred). The remaining expenditure that would be subject to CESS is a small portion of the total early works proposed expenditure. Further, as stated, as a proportion of the size of Marinus Link as a whole, the early works are small component of expenditure (around 5%). We consider the expenditure in Stage 1 Part A is relatively predictable and appropriate procurement processes can provide effective cost control. Our view is that an incentive mechanism is necessary so that Marinus Link continues to have incentives to make efficient decisions. We are not convinced that Marinus Link's suggested potential benefits of increased spending and risk-taking would outweigh those incentives. Of the stakeholders who provided submissions, only Marinus Link's Consumer Advisory Panel (CAP) commented on the CESS. The CAP considers the CESS should apply to incentivise cost control.[39]

As with HumeLink we believe forecast capex should be added to Marinus Link's CESS capex target, but that the decision on whether the CESS should apply should be deferred to when we know more about the full costs and risks of the project, following submission of the Stage 1, Part B (Construction costs) proposal. Adding the forecast capex to CESS capex target leaves us the option to apply CESS in that later period.

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36 AER, *AER - Determination - HumeLink Stage 1 (part 2) - August 2023*, August 2023, p. 12.

37 AER, *AER - Transgrid 2023-28 - Final Decision - Attachment 9 Capital expenditure sharing scheme - April 2023*, April 2023, p. 5.

38 AER, *AER – Final decision – Capital expenditure incentive guideline – 28 April 2023*, 28 April 2023, p.7.

39 Marinus Link, *Marinus Link - Revenue proposal - Stage 1 part A early works - 31 July 2023*, 31 July 2023, p. 27.

4 Pass through events

Under the Commencement and Process Paper, we are required to make a decision on the inclusion of pass throughs for Stage 1, Part A (Early works).[40]

The pass through regime in the NER does not directly fit with Marinus Link's Stage 1, Part A (Early works) scenario because it assumes the regulated entity is earning revenue. Materiality is defined by reference to a service provider's revenue. The pass through mechanism assumes costs passed through will be added to revenue.

The Commencement and Process Paper stated that the AER will make a constituent decision on pass through events from the Stage 1, Part A (Early works) stage.

Clause 6A.7.3(a1) of the Rules provides for the following cost pass through events:

- regulatory change event
- service standard event
- tax change event
- insurance event
- inertia shortfall event

In addition to these pass through events, the Rules allow each TNSP to nominate additional pass through events in its revenue proposal. In recent determinations, TNSPs have nominated the following events:[41]

- insurance coverage event
- terrorism event
- natural disaster event
- insurer credit risk event.

Marinus Link proposes that these nominated pass through events should apply for Stage 1, Part A (Early works). We do not have any in principle objection to Marinus Link having access to the same pass through events as other TNSPs. However, given the particular circumstances of Marinus Link, there are two matters we must determine: 1) how to set a materiality threshold in the absence of earning revenues 2) how Marinus Link will recover cost pass through amounts in the absence of revenues.

The NER requires that positive pass throughs meet a materiality threshold greater than 1% of maximum allowed revenue (MAR) in a regulatory year.[42] However, Marinus Link will not have a MAR (because it will not earn revenue) until the Stage 2 decision in 2029.

Marinus Link's proposed solution to this issue is to formulate a proxy Maximum Allowed Revenue (MAR) for each year of Stage 1 for the purposes of formulating a materiality threshold.[43] This involves using the return on capital component for each year as a proxy for the MAR.

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40 AER, *Marinus Link Decision: Transmission Determination Commencement and Process Paper,* June 2023.

41 For instance: AER, *AER - ElectraNet 2023-28 - Final decision - Attachment 13 - Cost pass through events - April 2023,* April 2023, pp. 4-7.

42 NER, Ch. 10, definitions of "positive change event" and "material".

43 Marinus Link, *Marinus Link - Revenue proposal - Stage 1 part A early works - 31 July 2023*, 31 July 2023, p. 42.

Allowed return on opening RAB = Allowed Return x Opening RAB

Allowed return on annual expenditure and equity raising costs = Allowed rate of return^0.5 x Expenditure (Early works) net of grant funding plus equity raising costs for 2021-22, 2022-23 and 2023-24, and Allowed rate of return^0.75 x Expenditure (Early works) net of grant funding plus equity raising costs for 2024-25

Debt raising costs = Debt raising cost rate x Debt gearing ratio x Opening RAB

MAR = Allowed return on opening RAB + Allowed return on annual expenditure and equity raising costs + Debt raising costs

We note that this will result in a small materiality threshold of between $40,000 and $70,000 for early works after applying the 1% factor to Marinus Link's proxy MAR estimate. While small, this is not out of step with TNSPs Directlink and MurrayLink, who also have small thresholds. We accept Marinus Link's proposed solution.

Marinus Link will not commence revenue recovery until 2029. Consequently, in the event of a cost pass through, Marinus Link will not have revenue to adjust for the impact of the event. Marinus Link has not proposed a methodology for recovering pass through amounts.

We consider the appropriate mechanism for recovery is to capitalise any adjustments for cost pass throughs. These would remain in the RAB until the full revenue and pricing determination is made in 2029. Additional amounts approved by the AER as part of a cost pass through application will be added to the approved capex forecast in the relevant regulatory year This is a modification to the existing pass through mechanism because the Marinus Link will not recover revenue in the period covered by this determination. The capitalisation of expenditure calculation is covered in section 6 below.

This is consistent with the process established for intending TNSPs to recover costs incurred before assets are commissioned (i.e., all efficient costs are capitalised and earn a rate of return until Marinus Link commences the supply of prescribed services).

We therefore determine to apply the pass through regime to Marinus Link, during the period for which it begins to earn revenue, as follows.

If Marinus Link applies to pass through a positive pass through amount under cl 6A.7.3(c) of the Rules, and the AER determines that a positive change event has occurred, the approved pass through amount will be added to the regulatory asset base for Marinus Link.

If Marinus Link notifies the AER of a negative change event under cl 6A.7.3(f), or the AER otherwise becomes aware of a negative change event, and the AER determines a negative pass through amount, the negative pass through amount will be deducted from the regulatory asset base for Marinus Link.

5 Rate of return

In this decision, the rate of return is calculated and applied each year for the purposes of capitalising Marinus Link's early works expenditure for its 'roll forward model' to establish its opening regulatory asset base on 1 July 2025.[44]

We are required by the NEL to apply the rate of return instrument (RORI) to estimate an allowed rate of return.[45] For this decision, we apply the 2022 Rate of Return Instrument (2022 Instrument), which specifies how we will estimate the return on debt, the return on equity, and the overall rate of return. In making an early works decision, we will be imposing regulatory control over Marinus Link and will effectively be setting a regulatory control period for the period from 1 July 2021 to 30 June 2025.

Marinus Link proposed that we should apply TasNetworks' rate of return.[46] We disagree with this view and address their arguments in the next section.

Our calculated rate of return in Table would apply to the first 3 years of the 2021–25 period. A different rate of return would apply for 2024-25, the remaining regulatory year. We update the return on debt component of the rate of return each year, in accordance with the 2022 Instrument, to use a 10-year trailing average portfolio return on debt that is rolled-forward each year. We use 2021-22 as the transition year. In subsequent years, only 10% of the return on debt is calculated from the most recent averaging period with 90% from prior periods.

Marinus Link did not nominate a risk-free rate[47] averaging period or debt averaging periods. We will apply the default risk-free rate averaging period and debt averaging periods in accordance with the 2022 Instrument.[48] We elaborate on this in Confidential Appendix A.

Table 3 Marinus Link's rate of return (nominal)

	AER's decision (2021–22)	AER's decision (2022–23)	AER's decision (2023–24)	Allowed return over the regulatory control period
Nominal risk-free rate	1.34%[a]	1.34%[a]	1.34%[a]	
Market risk premium	6.20%	6.20%	6.20%	
Equity beta	0.6	0.6	0.6	
Return on equity (nominal post-tax)	5.06%	5.06%	5.06%	Constant (%)
Return on debt (nominal pre-tax)	2.12%[b]	2.27%[b]	2.70%[b c]	Updated annually

44 Marinus Link, *Marinus Link - Revenue proposal - Stage 1 part A early works - 31 July 2023*, 31 July 2023, p.41.

45 AER, *Rate of Return Instrument 2022,* August 2023. The 2022 Rate of Return Instrument was amended in August 2023. See https://www.aer.gov.au/publications/guidelines-schemes-models/rate-of-return-instrument-2022/final-decision.

46 Marinus Link, *Marinus Link - Revenue proposal - Stage 1 part A early works - 31 July 2023*, 31 July 2023, p.41.

47 This is also known as the return on equity averaging period.

48 AER, *Rate of Return Instrument 2022*, cll.7(b), 23(b).

Gearing	60%	60%	60%	Constant (60%)
Nominal vanilla WACC	3.29%	3.39%	3.64%[c]	Updated annually for return on debt

Source: AER analysis.
(a) Calculated using the default averaging period.
(b) Calculated using the default averaging period.
(c) We will update the rate of return for 2024-25 after the averaging period passes.

5.1 Capital raising costs

In addition to compensating for the required rate of return on debt and equity, we provide an allowance for the transaction costs associated with raising debt and equity. Marinus Link proposed debt and equity raising costs based on TasNetworks' 2024-29 determination.[49] We apply an established benchmark approach for estimating debt and equity raising costs and have estimated an annual total debt raising cost of 8.88 bppa and subsequent equity raising cost of 3.0%. We have used these estimates to calculate the debt and equity raising cost forecasts for this determination.

5.2 The relevance of TasNetworks' rate of return

Marinus Link proposed to apply TasNetworks' rate of return and noted that it can be updated by the AER and readily applied for the purposes of establishing Marinus Link's opening regulatory asset base as at 1 July 2025.[50]

We consider that we are bound by the NEL to apply the RORI.[51] We have consulted with TasNetworks and Marinus Link on this matter. We have received two written submissions[52] and have also met with them. After reviewing the relevant information, our decision is that we must apply the current RORI to Marinus Link.

The NEL provides that the RORI is binding on the AER, and network service providers, "in relation to the performance or exercise of an AER economic regulatory function or power".[53] "AER economic regulatory function or power" is broadly defined in the NEL, and includes a power exercised by the AER under the NEL or Rules in making, or relating to the making of, a transmission determination.[54] Functions or powers that relate to the economic regulation of services provided by a regulated transmission system operator by means of, or in connection with, a transmission system, also fall within the definition of "AER economic regulatory function or power."[55]

We consider that our decision on Marinus Link's Stage 1 Part A revenue proposal falls within the definition of "AER economic regulatory function or power". This decision is likely a

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49 Marinus Link, *Marinus Link - Revenue proposal - Stage 1 part A early works - 31 July 2023*, 31 July 2023, p.42.

50 Marinus Link, *Marinus Link - Revenue proposal - Stage 1 part A early works - 31 July 2023*, 31 July 2023, p.41.

51 NEL, s18H.

52 Marinus Link, *Response to the AER's staff views on Rate of Return*, 20 October 2023; Marinus Link, *Further response to the AER's staff views on the allowed rate of return*, 30 October 2023.

53 NEL, s18H.

54 NEL, s2.

55 NEL, s2.

"transmission determination" within the meaning of the NER, or alternatively "a power relating to the making of" a transmission determination. Therefore, we are bound to apply the RORI in making this revenue determination.

Marinus Link does not contest the fact that we are bound by the RORI in making this determination. Marinus Link's submission regarding our need to comply with the RORI is that it would be consistent with the instrument for it to receive TasNetworks' rate of return, because TasNetworks' rate of return was calculated using the RORI.[56] We disagree with this argument, because it would imply that any TNSP's rate of return could be applied to Marinus Link, or any other TNSP. In other words, it would not be consistent with the RORI, and would therefore violate section 18H of the NEL, for the AER to apply TasNetworks' rate of return to Marinus Link. This is not a TasNetworks determination. We consider that the fact that we are bound by the RORI in relation to this determination means that we must determine Marinus Link's rate of return by applying the RORI to Marinus Link for the Stage 1 Part A period.

Marinus Link made other arguments in support of its submission that it would be appropriate for it to receive TasNetwork's rate of return. These were:

- As the early works determination relates to a period that pre-dates the commencement of the first regulatory control period, the allowed rate of return provisions in the Rules do not apply for Stage 1, Part A (Early works). [57]
- TasNetworks is financing Marinus Link's early works, thus it is appropriate for Marinus Link to receive TasNetworks' rate of return. [58]

We are not persuaded by these other arguments. None of them address the fact that we are bound by the NEL to apply the RORI when making this decision. We do not consider it is necessary to express a view on the other arguments put forward by Marinus Link regarding the rate of return.

56 Marinus Link, *Response to the AER's staff views on Rate of Return*, 20 October 2023, p.7.

57 Marinus Link, *Response to the AER's staff views on Rate of Return*, 20 October 2023, p. 1 and pp.3-5; Marinus Link, *Further response to the AER's staff views on the allowed rate of return*, 30 October 2023.

58 Marinus Link, *Response to the AER's staff views on Rate of Return*, 20 October 2023, pp.5-6; Marinus Link, *Further response to the AER's staff views on the allowed rate of return*, 30 October 2023.

6 Capitalisation of expenditure

This section sets out our calculation of the opening RAB as at 1 July 2025 for Marinus Link which includes the escalation of capitalised costs that Marinus Link will recover from customers as an incremental revenue in the first regulatory period commencing after commissioning.

Table below shows the calculation of the approved opening RAB as at 1 July 2025 for Marinus Link, which reflects our decision to accept the proposed early works expenditures capitalised at the allowed rate of return we have determined (section 5). The opening RAB as at 1 July 2025 reflects our approved:

- cost of the land purchases at Heybridge and Mardan Farm prior to 1 July 2021. For each land acquisition, Marinus Link obtained independent expert advice regarding the market value.
- expenditures for early works activities from 1 July 2021 to 31 December 2024
- equity raising cost which is broadly consistent with the method set out in the AER's post-tax revenue model (PTRM)
- return on capital for the above expenditures based on the allowed WACC (section 5)
- debt raising costs which is broadly consistent with the method set out in the AER's PTRM.

In determining the opening RAB as at 1 July 2025, we note the following:

- The benchmark debt and equity raising costs which have been capitalised into the RAB. This approach is consistent with standard regulatory practice, noting that these costs are included in the RAB because no revenue will be recovered relating to these benchmark allowances until prescribed services commence in 2029.
- The opening RAB calculation as at 1 July 2025 does not make any adjustment for depreciation because Marinus Link is not expected to be commissioned until January 2029 and, therefore, depreciation will not commence until 2029.
- Table does not include any forecast construction expenditure incurred prior to 1 July 2025, as this determination is on the Revenue Proposal focused on early works expenditure. We will amend the opening RAB as at 1 July 2025 to include any prudent and efficient construction expenditure forecast to be incurred prior to 1 July 2025 to be submitted by Marinus Link as part of its Revenue Proposal – Stage, 1 Part B (Construction costs).

Table 4 Capitalisation of expenditure calculation – Marinus Link Stage 1 Part A (Early Works) ($m, nominal)

	2021–22	2022–23	2023–24	2024–25
Opening RAB	5.0[a]	38.0	66.8	124.1
Expenditure (Early works) net of grant funding[b]	30.7	27.1	53.9	17.2
Equity raising cost[c]	1.6			
Allowed return on opening RAB[d]	0.2	1.3	2.4	4.8

Allowed return on annual expenditure and equity raising costs[e]	0.5	0.5	1.0	0.5
Debt raising costs[c]	0.0	0.0	0.0	0.1
Closing RAB	38.0	66.8	124.1	146.7

Source: AER analysis.

Note: The closing RAB as at 1 July 2025 excludes any forecast prudent and efficient construction expenditure incurred prior to 1 July 2025.

a The opening RAB as at 1 July 2021 reflects amounts spent prior to July 2021 for land acquisition at Heybridge and Mardan Farm.

b Assumed to be in mid-year December terms except for 2024-25. The 2024-25 expenditure reflects capex over a 6 month period from 1 July 2024 to 31 December 2024, assumed to be in 30 September 2024 dollar term.

c Updated equity raising cost and debt raising cost to reflect the allowed WACC as set out in section 5

d Calculated by multiplying the opening RAB with the allowed WACC.

e Calculated by multiplying the expenditure (early works) net of grant funding (including equity raising cost for 2021-22) with a 6-month WACC for 2021-22 to 2023-24 and a 9-month WACC for 2024-25.

We approve capital expenditure of $196.5 million inclusive of grant funding. Netting off grant funding of $67.6 million, we add $128.9 million net capex into the RAB over the 2021–22 to 2024–25 regulatory period. As a result, we approve an opening RAB as at 1 July 2025 of $146.7 million.

7 Consumer engagement

While the scope of the Stage 1, Part A (Early works) proposal is substantially narrower than a standard determination process, with the key issue being the prudency and efficiency of proposed early works expenditure, we consider consumer engagement remains an important aspect of the proposal.

Stakeholder engagement will be critical as Marinus Link progresses, both in terms of ensuring future regulatory proposals reflect consumer preferences and to develop and maintain social licence. We note consumer engagement commenced prior to the development of the Stage 1, Part A (Early works) proposal with consultation an important aspect of the Regulatory Investment Test – Transmission (RIT-T) process. The proposed scope of early works will advance stakeholder engagement with expenditure to support landowner and community engagement programs, including Traditional Owners, and stakeholder relations, activities we consider critical to progressing Marinus Link.

A key driver of consumer engagement has been the Consumer Advisory Panel (CAP), which has provided constructive challenge to Marinus Link to ensure its proposal delivers value to consumers. The CAP found the development of the early works proposal was a 'partnership', with Marinus Link engaging sincerely and providing comprehensive information when requested by CAP members.[59]

While the CAP noted its support for the Stage 1, Part (Early works) proposal, the report highlights a number of issues that will be critical to ongoing consumer engagement. These issues include the overall cost of Project Marinus for consumers, revenue allocation between jurisdictions and the extent to which consumers are able to influence the project.[60] We expect these issues will be the subject of going consumer engagement, both to maintain social licence and to inform the development the Stage 1, Part B (Construction cost) and Stage 2 revenue proposals.

Stakeholder submissions

The AER received three submissions on Marinus Link's Stage 1, Part A (Early works) proposal, from the Electrical Trades Union of Australia (ETU), the Tasmanian Minerals, Manufacturing and Energy Council (TMEC) and the independent Marinus Link CAP report.[61] Submissions raised the following key issues:

- Acknowledged the requirement for early works expenditure and noted the expectation that early works be diligent and minimise cost surprises or overruns during the construction phase.

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59 Consumer Advisory Panel, *Consumer Advisory Panel Engagement Process Report on the Marinus Link Proposal (Part A – Early Works Stage)*, September 2023, p. 11-12.

60 Consumer Advisory Panel, *Consumer Advisory Panel Engagement Process Report on the Marinus Link Proposal (Part A – Early Works Stage)*, September 2023, p. 11-12.

61 Consumer Advisory Panel, *Consumer Advisory Panel Engagement Process Report on the Marinus Link Proposal (Part A – Early Works Stage)*, August 2023; Electrical Trades Union, *ETU – Submission – Marinus Link – Stage 1 Part A early works – September 2023*, September 2023; Tasmanian Minerals and Energy Council, *TMEC – Submission – Marinus Link Stage 1 Part A early works – 14 September 2023*, September 2023.

- Highlighted corporate costs as the most significant incurred and forecast cost thus requiring further detail on how those costs have been determined to ensure prudent expenditure.
- Noted the importance of securing and maintaining social licence to the successful delivery of Marinus Link, including through ensuring local communities see the economic benefits from the investment, including training and employment opportunities.

We met with stakeholders, including Victorian and Tasmanian consumer peak group organisations and Energy Networks Australia (ENA). Key themes that emerged during those discussions include:

- Consumer groups noted there were questions as to the extent to which they could influence outcomes for large scale transmission projects that had ISP actionable status.
- Consumer groups noted it was difficult to fully appreciate the impact on consumers given uncertainty on key issues including the project cost, cost allocation between jurisdictions and treatment of concessionary finance.
- Acknowledgement that Marinus Link is critical to the National Electricity Market and broader energy transition.

Glossary

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CAP	Marinus Link's consumer advisory panel
CESS	Capital expenditure sharing scheme
CPA	Contingent Project Application
CPP	Commencement and Process Paper
capex	capital expenditure
DMIAM	Demand management innovation allowance mechanism
ENA	Energy Networks Australia
ETU	Electrical Trades Union of Australia
HVDC	High voltage direct current
ISP	Integrated System Plan
MAR	Maximum Allowed Revenue
MLPL	Marinus Link Proprietary Limited
NEL	National Electricity Law
NEO	National Electricity Objective
NER	National Electricity Rules
ODP	Optimal Development Path
PACR	Project Assessment Conclusion Report
PTRM	Post-tax Revenue Model
RAB	Regulatory Asset Base
RIT–T	Regulatory Investment Test for Transmission
ROR	Rate of return

Shortened form	Extended form
RORI	Rate of return instrument
SSIS	Small-scale incentive scheme
TMEC	Tasmanian Minerals, Manufacturing and Energy Council
TNSP	Transmission Network Service Provider
VNI West	Victoria to New South Wales Interconnector West
WACC	Weighted average cost of capital

The economic contribution of Project Marinus

Marinus Link

October 2023

Building a better working world

Notice

Ernst & Young was engaged on the instructions of Marinus Link ("Client")] to estimate the economic contribution of Project Marinus ("Project")], in accordance with the service order dated 2 August 2023.

The results of Ernst & Young's work, including the assumptions and qualifications made in preparing the report, are set out in Ernst & Young's report dated October 2023 ("Report"). The Report should be read in its entirety including the transmittal letter, the applicable scope of the work and any limitations. A reference to the Report includes any part of the Report.

Ernst & Young has prepared the Report for the benefit of the Client and has considered only the interests of the Client. Ernst & Young has not been engaged to act, and has not acted, as advisor to any other party. Accordingly, Ernst & Young makes no representations as to the appropriateness, accuracy or completeness of the Report for any other party's purposes.

Our work commenced on 02 August 2023 and was completed on 20 October 2023. No further work has been undertaken by EY since the date of the Report to update it, and EY has no responsibility to update the Report to take account of events or circumstances arising after that date. Therefore, our Report does not take account of events or circumstances arising after 20 October 2023.

No reliance may be placed upon the Report or any of its contents by any party other than the Client ("Third Parties"). Any Third Party receiving a copy of the Report must make and rely on their own enquiries in relation to the issues to which the Report relates, the contents of the Report and all matters arising from or relating to or in any way connected with the Report or its contents.

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In preparing this Report Ernst & Young has considered and relied upon information from a range of sources believed to be reliable and accurate. We have not been informed that any information supplied to it, or obtained from public sources, was false or that any material information has been withheld from it. Neither Ernst & Young nor any member or employee thereof undertakes responsibility in any way whatsoever to any person in respect of errors in this Report arising from incorrect information provided to EY

Ernst & Young does not imply and it should not be construed that it has verified any of the information provided to it, or that its enquiries could have identified any matter that a more extensive examination might disclose.

The analysis and Report do not constitute a recommendation on a future course of action.

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Ernst & Young's liability is limited by a scheme approved under Professional Standards Legislation.

Ben Gourlay
Head of Government Relations
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25 October 2023

Building a better working world

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Dear Ben

In accordance with our Engagement Agreement dated 2 August 2023 ("Agreement"), Ernst & Young ("we" or "EY") has been engaged by the Marinus Link ("you" or the "Client") to provide an economic contribution report (the "Services"). The enclosed report (the "Report") sets out the outcomes of our work. You should read the Report in its entirety. A reference to the report includes any part of the Report.

Purpose of our Report and restrictions on its use

Please refer to a copy of the Agreement for the restrictions relating to the use of our Report. We understand that the deliverable by EY will be used for the purpose of understanding the economic benefits of Project Marinus (the "Purpose"). This Report was prepared on the specific instructions of the Marinus Link solely for the Purpose and should not be used or relied upon for any other purpose. This Report and its contents may not be quoted, referred to or shown to any other parties except as provided in the Agreement. We accept no responsibility or liability to any person other than to Marinus Link or to such party to whom we have agreed in writing to accept a duty of care in respect of this Report, and accordingly if such other persons choose to rely upon any of the contents of this Report they do so at their own risk.

Nature and scope of our work

The scope of our work, including the basis and limitations, are detailed in our Agreement and in this Report. Our work commenced on 02 August 2023 and was completed on 20 October 2023. No further work has been undertaken by EY since the date of the Report to update it, and EY has no responsibility to update the Report to take account of events or circumstances arising after that date. Therefore, our Report does not take account of events or circumstances arising after 20 October 2023. In preparing this Report we have considered and relied upon information from a range of sources believed to be reliable and accurate. We have not been informed that any information supplied to us, or obtained from public sources, was false or that any material information has been withheld from us. We do not imply and it should not be construed that we have verified any of the information provided to us, or that our enquiries could have identified any matter that a more extensive examination might disclose. The work performed as part of our scope considers information provided to us and [only a combination / a number of combinations] of input assumptions relating to future conditions, which may not necessarily represent actual or most likely future conditions. Additionally, modelling work performed as part of our scope inherently requires assumptions about future behaviours and market interactions, which may result in forecasts that deviate from future conditions. There will usually be differences between estimated and actual results, because events and circumstances frequently do not occur as expected, and those differences may be material. We take no responsibility that the projected outcomes will be achieved, if any. We highlight that our analysis and Report do not constitute investment advice or a recommendation to you on a future course of action. We provide no assurance that the scenarios we have modelled will be accepted by any relevant authority or third party. Our conclusions are based, in part, on the assumptions stated and on information provided by Marinus Link and other information sources used during the course of the engagement . The modelled outcomes are contingent on the collection of assumptions as agreed with Marinus Link and no consideration of other market events, announcements or other changing circumstances are reflected in this Report. Neither Ernst & Young nor any member or employee thereof undertakes responsibility in any way whatsoever to any person in respect of errors in this Report arising from incorrect information provided by Marinus Link or other information sources used. This letter should be read in conjunction with our Report, which is attached.

Yours sincerely

Lars Rognlien, Associate Partner

Executive summary

Project Marinus - Connecting economies and communities

Project Marinus includes both Marinus Link and the North-West Transmission Developments (NWTD). Marinus Link is a proposed undersea DC transmission link (and telecommunications connector) between Tasmania and Victoria. Construction for Stage 1 of Project Marinus is expected to commence in 2025 and will take around five years to complete.[1]

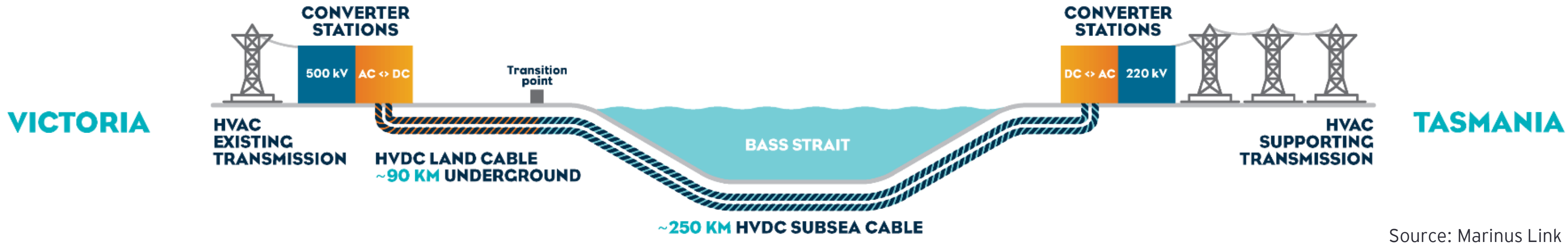
The construction and operations of Project Marinus are expected to provide **$2,094 million** in economic contribution for Tasmania, as well as **$1,781 million** in economic contribution for Victoria. [2] This consists of:

- Stage 1 of Marinus Link, which is expected to provide **$836 million** in economic contribution for Tasmania and **$1,008 million** in economic contribution for Victoria.
- Stage 2 of Marinus Link, which is expected to provide **$641 million** in economic contribution for Tasmania and **$773 million** in economic contribution for Victoria.
- The NWTD, which is expected to provide **$617 million** in economic contribution for Tasmania.

During the peak construction period (2027 to 2029), Project Marinus is expected to support an average of **1,644** jobs per year in Tasmania and **1,675** jobs per year in Victoria, consisting of:

- Stage 1 of Marinus Link, which supports an average of **673** jobs per year in Tasmania and **857** jobs per year in Victoria.
- Stage 2 of Marinus Link, which supports an average of **643** jobs per year in Tasmania and **818** jobs per year in Victoria.
- The NWTD, which supports an average of **328** jobs per year in Tasmania.

In addition, during the peak construction period for Stage 1 only (2025 to 2027), Stage 1 of Marinus Link and the NWTD are expected to support an average of **1,424** jobs per year in Tasmania and **993** jobs per year in Victoria.



Source: Marinus Link

1. Information about Project Marinus' costs and development timeframe were provided by Marinus Link
2. The economic contribution (value add) and job years (used here to represent FTE years) presented are the total impact (direct, indirect and induced). Project Marinus is assumed to be operational from 2030 – 2050 (20 years). All values are in real 2023 AUD. Refer to page 12 for a detailed explanation of the interpretation of economic contribution (value add) and FTE. These numbers are gross consistent with the application of economic contribution analysis.

Overview

This Report

Marinus Link has engaged EY to undertake an assessment of the economic contribution of Project Marinus (which includes both Marinus Link and the North-West Transmission Developments) construction and operating phases. The analysis provided is also intended to assist in quantifying the contribution of any projects that may be enabled by the construction and operations of Marinus Link. Economic contribution is a gross measure rather than a net measure of the contribution of an industry or a project to the economy and does not consider substitution impacts, or what would happen if the relevant industry did not exist, or the relevant project did not occur. The value-add estimates are therefore gross measures, as are employment impacts.

This report is an update to the 2019 report for Marinus Link. This version of the report uses updated multipliers (from 2020-21), and new Project Marinus construction and operating costs provided by Marinus Link. This version of the report also draws from updated energy market modelling from the 2021 Project Assessment Conclusions Report (PACR) submission.

Project Marinus

Project Marinus includes Marinus Link (or the Second Bass Strait DC Interconnector) ("Marinus Link"), along with significant supporting on-island AC transmission upgrades (The North-West Transmission Developments ("NWTD")). Project Marinus is planned to deliver a High Voltage Direct Current (HVDC) electricity transmission connection between mainland Victoria and Tasmania. If built as planned, Marinus Link will complement the existing Basslink interconnector, which began trading energy between Tasmania and Victoria via the National Electricity Market in 2006. Project Marinus is expected to be completed in two stages ("Stage 1" and "Stage 2"). Each stage is expected to take five years to construct. The estimated project cost for Marinus Link (between 2025 and 2030) used in this analysis is $5.9 billion, with a further $0.8 billion for the NWTD (between 2025 and 2030).[1]

Note that updated costs were released for Project Marinus after the completion of the analysis presented in this report. As of September 2023, Marinus Link is estimated to cost between $5 and $5.5 billion. The analysis in this report uses the previous estimated cost of $5.9 billion.

Tasmanian renewable energy projects enabled by Project Marinus

Marinus Link is expected to induce the investment in further renewable electricity generation in Tasmania to meet the growing demand for cleaner energy from the National Electricity Market (NEM). The magnitude of installed capacity (MW) and timeframe is estimated using EY's "Market Model", which forecasts generator dispatch and new builds. This analysis considers two Australian Energy Market Operator (AEMO) 2020 Integrated System Plan scenarios:

- **Central –** this scenario reflects the transition of the energy industry under current policy settings and technology trajectories.
- **Step Change –** under this scenario it is assumed Australia takes strong action on climate change. The NEM targets a 90% reduction in emissions from 2016 levels by 2050. In this scenario, aggressive global decarbonisation leads to faster technological improvements.

The analysis of induced investment in both scenarios focuses on the incremental capacity. That is, the resulting capacity over and above a base case where Marinus Link does not proceed.

Potential Tasmanian Data Hub

Project Marinus also includes the installation of data communications equipment, which is expected to add substantial telecommunications capacity for Tasmania. This report estimates the economic contribution of enabling further data centre capacity, based on MW of additional data hub capacity provided to EY by Marinus Link. These benefits consider the economic contribution of the construction of additional data centre capacity in Tasmania as a result of Project Marinus.

1. This information was provided by Marinus Link. Note that this analysis does not include NWTD costs from 2024, as the modelling period is from 2025-2050.

Economic contribution analysis – value add

Our approach involves using economic contribution analysis to capture the direct effects of an industry (i.e. revenues or output) relevant to Tasmania and Victoria. We then apply an economic multiplier to capture the flow-on (or 'indirect and induced') effects of Project Marinus's construction and operating phases. We applied this same process to the additional renewable energy projects and data centre capacity in Tasmania enabled by Project Marinus. The results in the below table assumes that both Marinus Link and the NWTD are both operational by 2030. The results here are the total over the modelling period (2025 – 2050), have not been discounted and are in real 2023 AUD.

Total estimated value add supported in Tasmania and Victoria as part of construction and operations of Project Marinus and Tasmanian enabled investments, (2025 – 2050), real 2023 $m.

Value add, 2023 $m	Marinus Link - Stage 1		Marinus Link - Stage 2		North-West Transmission Developments	Tasmanian renewable energy projects enabled by Project Marinus[1]				Potential Tasmanian Data Hub[2]
	Tasmania	*Victoria*	*Tasmania*	*Victoria*		*Scenario 1. Central*	*Scenario 2. Step Change*	*Scenario A1. Central - 50% new wind*	*Scenario A2. Step Change - 50% new wind*	
Construction										
Direct	359	359	261	261	277	674	1,255	643	1,768	960
Indirect	197	266	143	193	152	370	688	352	969	526
Induced	154	231	112	168	119	289	539	276	759	412
Subtotal	710	856	515	621	548	1,334	2,481	1,271	3,496	1,899
Operations										
Direct	62	62	62	62	34	38	160	222	254	
Indirect	44	60	44	60	24	31	133	184	211	
Induced	19	30	19	30	10	13	57	79	91	
Subtotal	126	152	126	152	69	82	350	485	556	
Total	836	1,008	641	773	617	1,416	2,831	1,756	4,052	1,899

Source: EY analysis of Marinus Link data and the 2021 PACR modelling submission

Note that this analysis does not consider what investments would take place outside Tasmania in the absence of the Marinus Link Project, including any renewable or other generation capacity.

1. As identified in the 2021 PACR modelling submission. These values are driven by the difference in renewable energy projects when comparing each AEMO scenario with and without Project Marinus. The original scenarios (1 and 2) are based purely on the 2021 PACR modelling, while the alternate scenarios (A1 and A2) assume that 50% of all new wind generation as identified in the PACR modelling is enabled by Marinus Link. Further details on these scenarios can be found on page 26.
2. Based on the construction of the additional MW of data centre capacity in Tasmania and not in Victoria, provided by Marinus Link.

Economic contribution analysis - FTE

The results in the table below assumes that both Marinus Link and the NWTD are operational by 2030. The FTE years are the total impact (direct, indirect and induced) from 2025 to 2050. An 'FTE-year' represents one full time equivalent role supported for a full year – for instance, 1,000 FTE-years may be 500 FTE sustained over 2 years, or 100 FTE sustained over 10 years.

Total estimated FTE years supported in Tasmania and Victoria as part of construction and operations of Project Marinus and Tasmanian enabled investments (2025 – 2050)

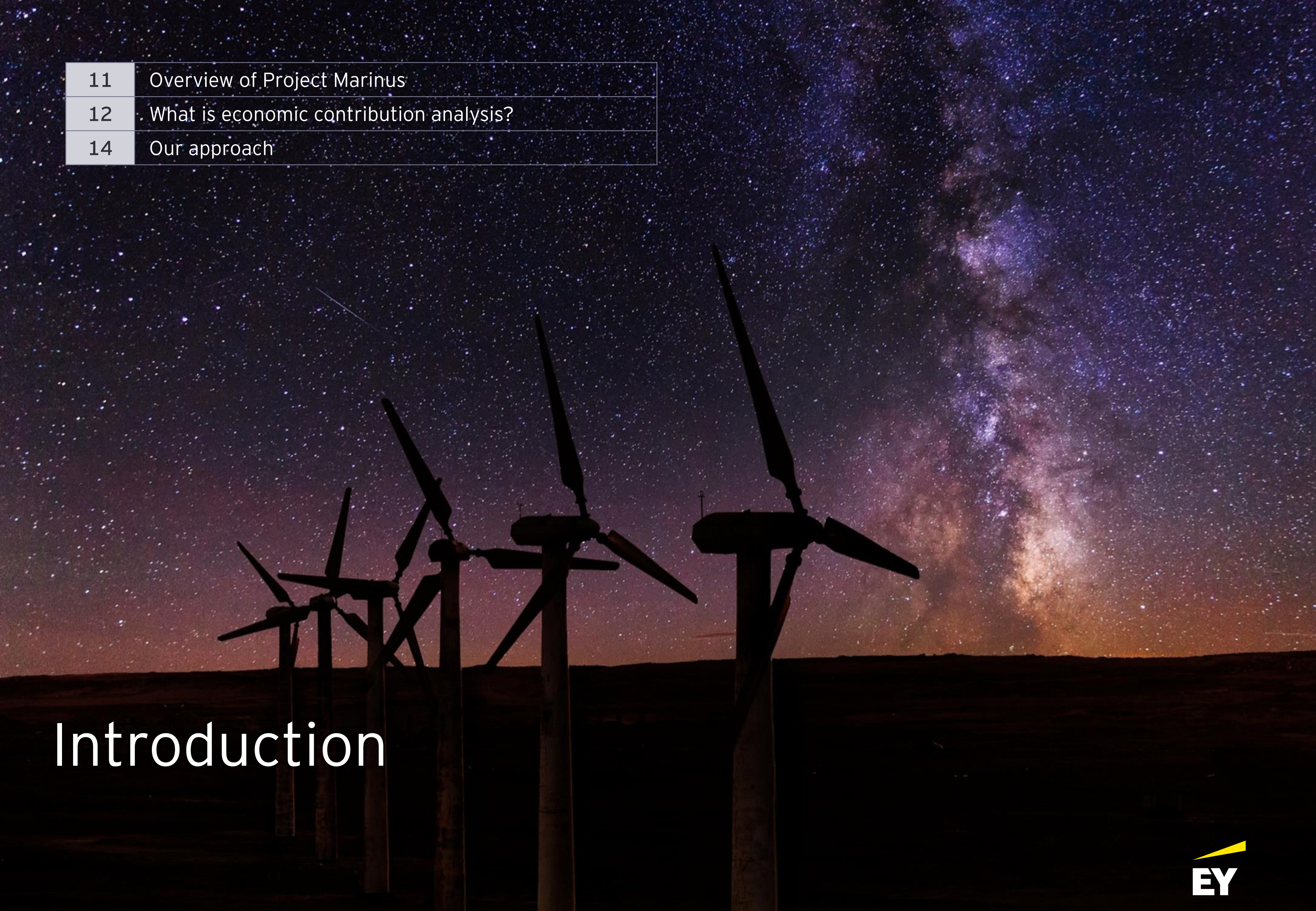
FTE years	Marinus Link - Stage 1		Marinus Link - Stage 2		North-West Transmission Developments	Tasmanian renewable energy projects enabled by Project Marinus[1]				Potential Tasmanian Data Hub[2]
	Tasmania	*Victoria*	*Tasmania*	*Victoria*		*Scenario 1. Central*	*Scenario 2. Step Change*	*Scenario A1. Central - 50% new wind*	*Scenario A2. Step Change - 50% new wind*	
Construction										
Direct	844	844	613	613	651	1,585	2,949	1,511	4,154	2,256
Indirect	1,330	1,726	966	1,253	1,026	2,499	4,649	2,382	6,549	3,557
Induced	960	1,417	697	1,029	741	1,803	3,354	1,718	4,725	2,566
Subtotal	3,134	3,987	2,275	2,894	2,418	5,886	10,951	5,611	15,429	8,380
Operations										
Direct	124	124	124	124	68	53	224	311	356	
Indirect	149	207	149	207	82	112	478	662	759	
Induced	118	183	118	183	65	84	356	493	565	
Subtotal	391	513	391	513	214	248	1,058	1,466	1,680	
Total	3,524	4,500	2,666	3,408	2,632	6,134	12,009	7,077	17,109	8,380

Source: EY analysis of Marinus Link data and the 2021 PACR modelling submission

Note that this analysis does not consider what investments would take place outside Tasmania in the absence of the Marinus Link Project, including any renewable or other generation capacity.

1. As identified in the 2021 PACR modelling submission. These values are driven by the difference in renewable energy projects when comparing each AEMO scenario with and without Project Marinus. The original scenarios (1 and 2) are based purely on the 2021 PACR modelling, while the alternate scenarios (A1 and A2) assume that 50% of all new wind generation as identified in the PACR modelling is enabled by Marinus Link. Further details on these scenarios can be found on page 26.
2. Based on the construction of the additional MW of data centre capacity in Tasmania and not in Victoria, provided by Marinus Link.

Table of contents



Introduction

Overview of Project Marinus

Project Marinus includes both Marinus Link and the North-West Transmission Developments (NWTD). Marinus Link is a proposed two-cable undersea DC transmission link (and telecommunications connector) between Tasmania and Victoria. The NWTD is a major transmission upgrade in Tasmania. Together, the aim for the NWTD and Marinus Link is to play an integral role in supporting Australia's transition to a clean energy future.

Marinus Link is currently in the design and approvals phase, with a final investment decision expected in late 2024. Stage 1 (cable 1) is expected to begin construction in 2025 and Stage 2 (cable 2) in 2027. Construction on Marinus Link is expected to be completed by 2030. The NWTD is expected to begin construction in 2024 and is also due to be completed in 2030. In total, the construction phase of Project Marinus is expected to cost $6.7 billion real 2023 AUD between 2025 and 2030.[1]

Indicative high-level construction costs, 2025 onwards ($m, real 2023 AUD)

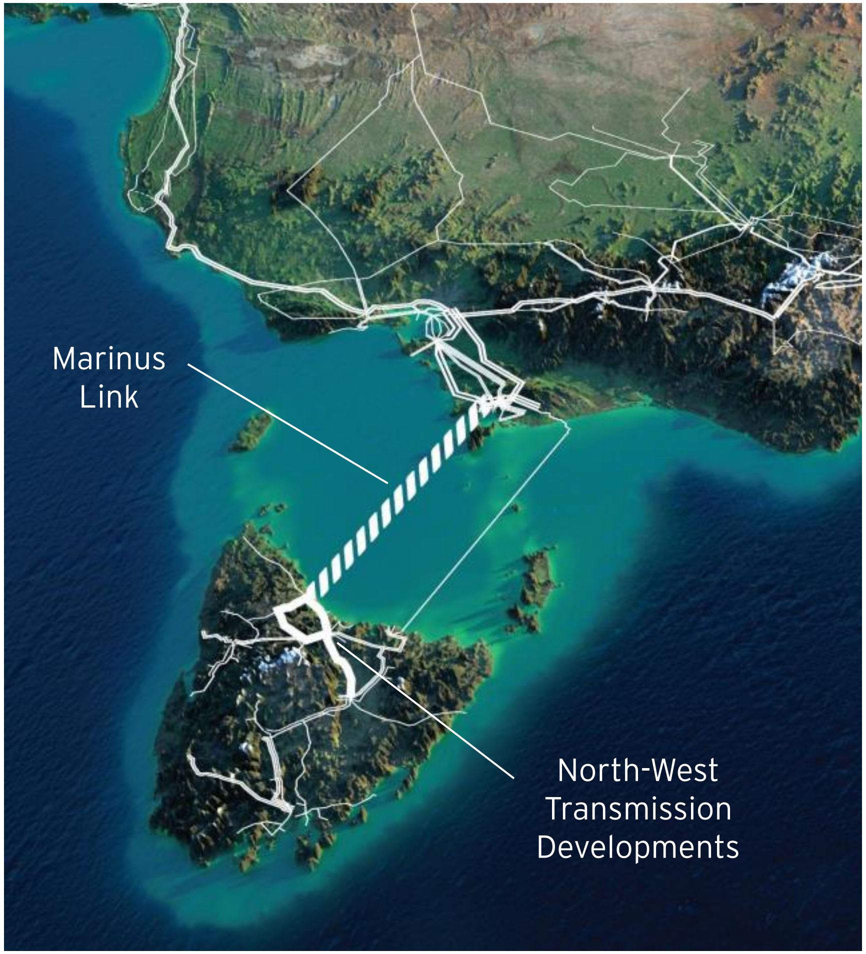
	Tasmania	Victoria
Stage 1	1,637	1,637
Stage 2	1,320	1,320
NWTD	810	-
TOTAL	3,767	2,957

Source: Marinus Link

Indicative annual operating costs ($m, real 2023 AUD)

	Tasmania	Victoria
Stage 1	8.4	8.4
Stage 2	8.4	8.4
NWTD	4.6	-
TOTAL	21.4	16.8

Source: Marinus Link



1. Project Marinus costs and development timeframe were provided by Marinus Link

What is economic contribution analysis?

Economic contribution analysis measures market related direct and indirect expenditure and economic activity generated by a specific industry and / or activity. Direct contribution analysis involves understanding and mapping the contributions directly attributable to an activity (i.e. the construction of Project Marinus). The key direct impacts will come from capital and operating expenditures, employment and tax contributions associated with Project Marinus' construction and operations and the construction and operations of its induced investment. These processes will also directly contribute to value add and jobs.

Indirect economic contribution involves mapping the flow-on impacts from a proposed industry / activity as the direct impacts of the activity flow through the economy. These flow-on impacts are typically reflected through the supply chain effects as more goods and services are demanded and consumption effects where a proportion of wages and salaries paid to workers are spent on consumptions activities.

Economic contribution components

	Direct economic contribution	+	Indirect effect	+	Induced effect	=	Total economic contribution
General Definition	Total revenue generated by an industry plus value-add taxes		Flow-on contribution generated by an industry purchasing inputs		Flow-on contribution generated by an industry's employees purchasing goods and services with their income		
Example	Industries earn revenue from selling inputs to Project Marinus' construction and operations		Flow-on (indirect) contribution generated by industries purchasing inputs (e.g. concrete)		Flow-on (induced) contribution generated by industry employees purchasing goods and services (e.g. education)		

Economic contribution is a gross measure rather than a net measure of the contribution of an industry or a project to the economy.

Economic contribution studies do not consider substitution impacts, or what would happen if the relevant industry did not exist, or the relevant project did not occur.

The value-add estimates are therefore gross measures, as are employment impacts.

Some common terms used throughout this report

Gross Value Add (GVA)

Gross value add (GVA) is typically estimated as the market value of goods and services produced, after deducting the cost of goods and services used. It represents the sum of all wages, income and profits generated.

All numbers cited in this report refer to GVA. An economic contribution analysis model is a high-level model with significant simplifying assumptions, and results should be interpreted with this in mind.

When reporting gross value add figures, it is good practice to always describe the period for which the value add figure applies. We use both economic contribution and GVA interchangeably throughout this report.

Full-time equivalent (FTE)

The jobs results presented in this report reflect the gross employment demand that would arise in Tasmania as a consequence of the construction and operations of Project Marinus.

The employment footprint disregards any displacement effects – i.e. it does not make assumptions about whether or not the jobs are net additional. The footprint estimates are suited to understand the overall job opportunities and needs that Project Marinus is expected to generate. The FTE numbers in this report are estimates, based on sector employment multipliers applied to installation costs. FTE year estimates may differ to the actual number of workers directly employed by in any given year.

All jobs in this economic contribution analysis represent "FTE years" – An 'FTE-year' represents one full time equivalent job supported for a full year – for instance, 1,000 FTE years may be 500 FTE jobs sustained over 2 years, or 100 FTE jobs sustained over 10 years.

Good practices when reporting these gross employment figures include:

- Always describing the period for which the FTE figure applies; e.g. "for the construction period" or "for ten years", etc.
- Avoiding phrases that assume economic constraints have already been accounted for, e.g. stating that the Project "supports 10,000 FTE jobs" or "expects to result in" is more accurate than "supports 10,000 new FTE roles"; and being clear that the figures are gross jobs, not net.
- Employment figures should not be added to other projects undertaken in Tasmania.

Our approach

The economic contribution analysis presented in this Report models total construction and operations costs of the following components:

Project Marinus

1. The total capital costs are estimated to be approximately $5.9 billion for Marinus Link (between 2025 and 2030) and $0.8 billion[1] for the NWTD (between 2025 and 2030)
2. Equipment costs (e.g. the transmission cables) were removed from the input costs in the estimation of value add as most of the equipment cost for Marinus Link will be sourced primarily from overseas. This is a conservative assumption.
3. The residual capital cost and total operations cost were then allocated to the jurisdiction where the cost is likely to be incurred. On the advice of Marinus Link, costs were split on an 50/50 basis between Victoria and Tasmania respectively, unless the specific jurisdiction of the cost was identified.
4. Installation and operations multipliers were applied to the residual costs to estimate value add and FTE years supported.

Tasmanian renewable energy projects enabled by Project Marinus

1. The EY 2021 PACR modelling estimated the resulting capacity in Tasmania over and above the base case of no Marinus Link being installed. These were used to estimate incremental capital and operating costs for renewable energy investments in Tasmania. EY did not consider any changes to generation capacity elsewhere in the NEM.
2. Multipliers were then applied to construction and operations costs to determine value add and FTE years supported.

Potential Tasmanian Data Hub

1. Marinus Link provided EY with information about additional data centre capacity as a result of Project Marinus. This was used to estimate the capital cost of data centre construction in Tasmania. The operating cost was not modelled (for more information see Appendix D) and EY did not consider any changes in data centre capacity elsewhere.
2. Multipliers were then applied to construction costs to determine value add and FTE years supported.

Data sources

Data sources used to inform calculations in this report include:

- **Information provided by Marinus Link –** Project Marinus' capital and operating expenditure, as well as estimates of future data centre capacity in Tasmania.
- **Australian National Accounts: Input-Output Tables for 2020-21 –** Used to calculate economic multipliers for use in this analysis
- **Marinus Link's 2021 PACR market modelling:** This was produced by EY using EY's energy market model. This modelling provided forecasts of potential investments induced by Marinus Link. This includes information on:
  - Planned investments in renewable energy in MW until 2050 for hydro, solar and wind electricity generation investments in Tasmania;
  - Fixed operating and maintenance costs ($/kw);
  - Variable operating and maintenance costs ($/kw);
  - Capital expenditure costs ($/kW);
- **Turner & Townsends, Data Centre Cost Trends Report, 2022 –** used to calculate an estimate of total capital expenditure based on capacity figures provided by Marinus Link.

All numbers in this report are in real 2023 million AUD. All years referred to in this report are financial years. Some figures in this report have been rounded for ease of communication. As a result, not all figures will reconcile exactly to totals (e.g. in some tables).

More information about our methodology is included in Appendix A – D.

1. This analysis does not include NWTD costs from 2024, as the modelling period is from 2025-2050.

Project Marinus

Overview of Project Marinus' construction and operating profile

Construction

The construction of Marinus Link is expected to take five years for each link and is staggered.[1] Stage 1 is expected to begin construction in 2025 and Stage 2 is expected to begin construction in 2027. Construction of the North-West Transmission Development is expected to begin in 2024 and finish in 2030, but this analysis only considers 2025 onwards. Broadly, the construction phase requires:

- Purchase of intermediate inputs such as metal and metal alloys, cable and converters and construction materials; and
- Construction, financing and project management services.

Core physical components of the interconnector include:

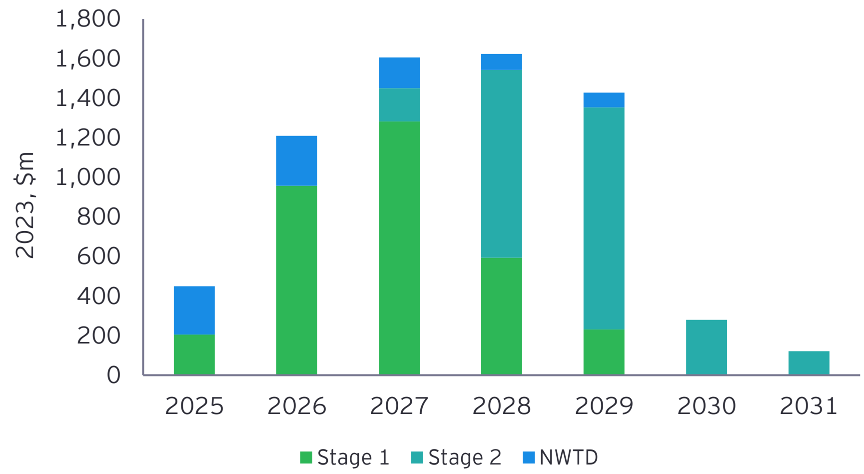
- Two 750 MW DC undersea transmission cables, delivered under a staggered timeframe;
- Transmission line(s) or cable(s) AC which transmit electricity (to and from the undersea cable) over land to converter stations;
- Two converter stations which convert direct current (DC) to alternating current (AC) and vice versa; and
- Augmentation of Tasmanian AC Network to support HVDC Link.

Operations

Project Marinus is expected to begin operations in 2030. Annual operating costs are expected to be $16.8 million per annum in Tasmania and $16.8 million per annum in Victoria for both Marinus Links 1 and 2, with an additional $4.6 million per annum in Tasmania for the NWTD.

Operations of Project Marinus have been modelled from 2030 – 2050.

Construction profile of Project Marinus



Source: EY analysis of Marinus Link data

Operating profile of Project Marinus

	Marinus Link - Stage 1	Marinus Link - Stage 2	North-West Transmission Development
Period included	2030-2050	2030-2050	2030-2050
Annual operating cost (2023, $m)	16.76	16.76	4.60

Source: EY analysis of Marinus Link data

1. Project Marinus costs and development timeframe were provided by Marinus Link

Tasmania - construction of Marinus Link

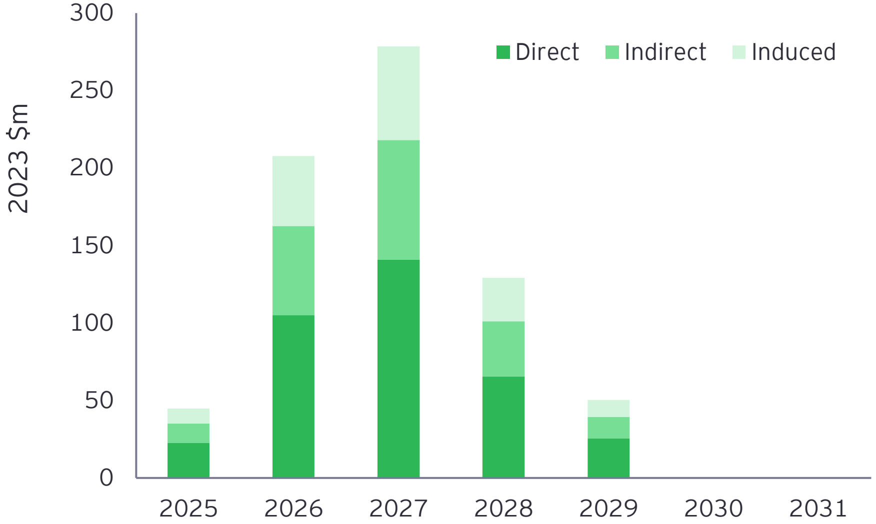
The construction cost of Marinus Link attributable to Tasmania is estimated at $1,637 million for Stage 1 and $1,320 million for Stage 2. The peak year for construction is estimated to be in 2028.

Between 2025 and 2032, construction of Marinus Link Stage 1 is expected to support value add of $710 million (direct, indirect and induced), while Stage 2 is expected to support value add of $515 million (direct, indirect and indirect).

Between 2025 and 2032, construction of Marinus Link Stage 1 is expected to support 3,134 FTE years, while Stage 2 is expected to support 2,275 FTE years.

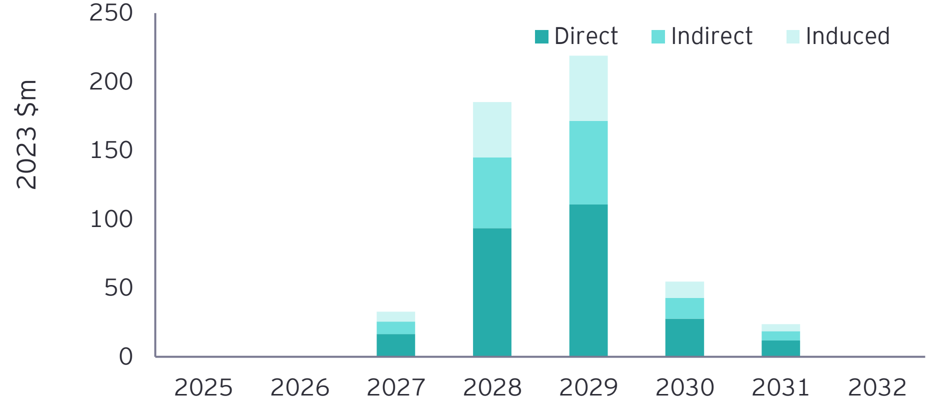
Overall, the construction of Marinus Link in Tasmania is expected to support 1,456 direct and 3,953 indirect and induced FTE years.

Marinus Link - Stage 1 value add in Tasmania



Source: EY analysis of Marinus Link data

Marinus Link - Stage 2 value add in Tasmania



Source: EY analysis of Marinus Link data

FTE years supported in Tasmania during construction of Marinus Link Stage 1 and Stage 2

	2025	2026	2027	2028	2029	2030	2031
Stage 1							
Direct	53	247	331	153	60	0	0
Indirect	84	389	522	242	94	0	0
Induced	60	281	376	174	68	0	0
Stage 2							
Direct			39	220	260	65	28
Indirect			61	347	410	102	44
Induced			44	250	296	74	32
Total							
Direct	53	247	370	373	320	65	28
Indirect	84	389	583	589	505	102	44
Induced	60	281	421	425	364	74	32

Source: EY analysis of Marinus Link data

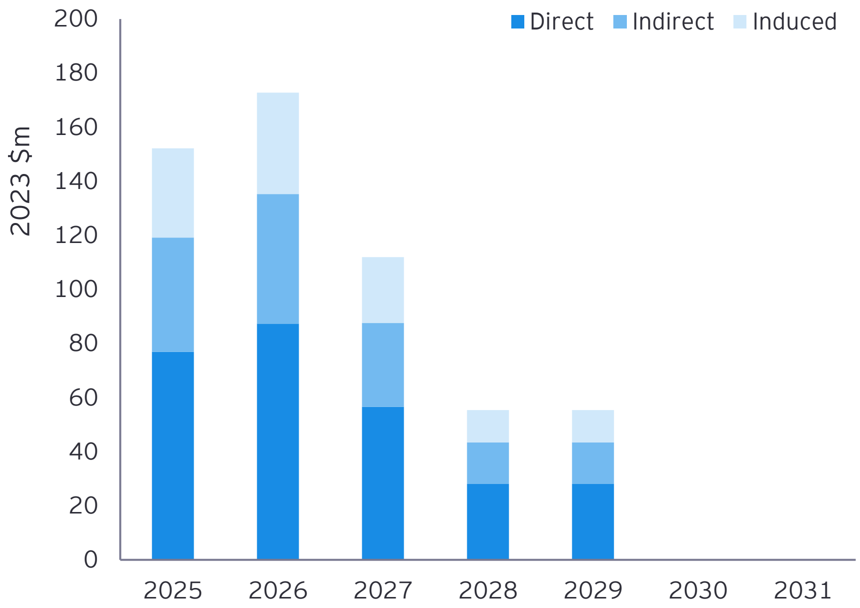
Tasmania - construction of the North-West Transmission Developments

The construction cost of the NWTD is estimated at $810 million. The peak year for construction is estimated to be in 2026.

Construction of the NWTD is expected to support value add of $548 million (direct, indirect and induced) and 2,418 FTE years.

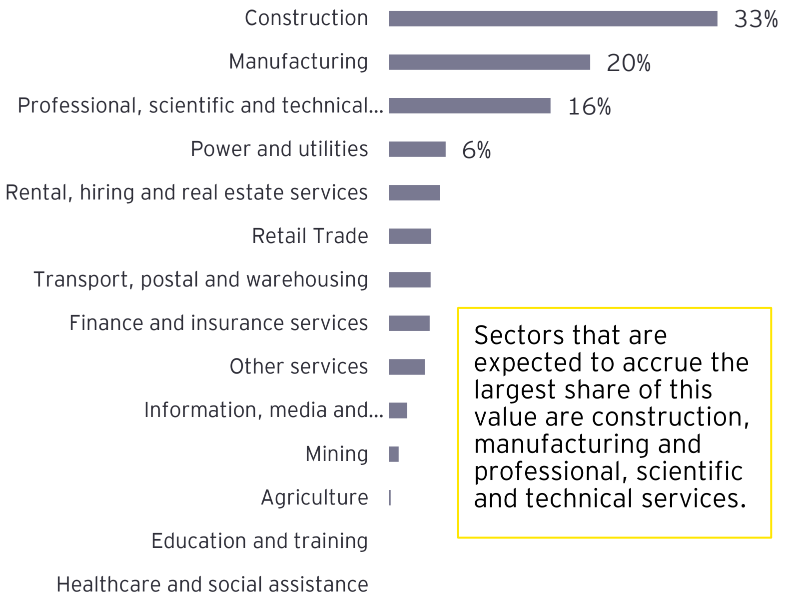
Overall, the construction of the NWTD in Tasmania is expected to support 651 direct and 1,767 indirect and induced FTE years.

NWTD - value add in Tasmania



Source: EY analysis of Marinus Link data

Sectors expected to accrue the largest share of value add (%)



Sectors that are expected to accrue the largest share of this value are construction, manufacturing and professional, scientific and technical services.

Source: EY analysis of ABS data

FTE years supported in Tasmania during construction of NWTD

	2025	2026	2027	2028	2029	2030	2031
NWTD							
Direct	181	205	133	66	66	0	0
Indirect	285	324	210	104	104	0	0
Induced	206	234	151	75	75	0	0

Source: EY analysis of Marinus Link data

Tasmania - Project Marinus operations

The operations cost of Marinus Link Stage 1 and Stage 2 attributable to Tasmania is estimated to be $8.4 million per stage, annually, The operations cost of the NWTD is expected to be $4.6 million annually. Project Marinus is expected to be operational in 2030 and the results here have been modelled out to 2050.

Operating cost of Project Marinus attributable to Tasmania

	Marinus Link - Stage 1	Marinus Link - Stage 2	North-West Transmission Developments
Period included	2030-2050	2030-2050	2030-2050
Annual operating cost (2023, $m)	16.76	16.76	4.60

Source: EY analysis of Marinus Link data

Operations of Marinus Link Stage 1 in Tasmania is expected to support value add of $126 million. Operations of Marinus Link Stage 2 in Tasmania is expected to support value add of $126 million. Operations of the NWTD in Tasmania is expected to support value add of $69 million.

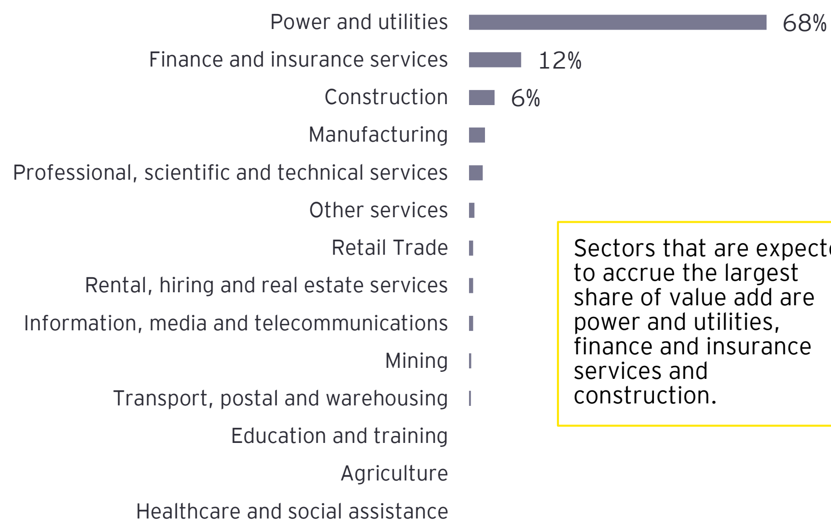
The operations of Marinus Link Stage 1 and Stage 2 are each expected to support 391 FTE years. Operations of the NWTD is expected to support 214 FTE years.

Value add and FTE years supported in Tasmania during operations of Project Marinus

	Marinus Link - Stage 1		Marinus Link - Stage 2		North-West Transmission Developments	
	Value add (2023, $m)	FTE	Value add (2023, $m)	FTE	Value add (2023, $m)	FTE
Annual						
Direct	3.0	5.9	3.0	5.9	1.6	3.2
Indirect	2.1	7.1	2.1	7.1	1.2	3.9
Induced	0.9	5.6	0.9	5.6	0.5	3.1
Total (2030-2050)						
Direct	62	124	62	124	34	68
Indirect	44	149	44	149	24	82
Induced	19	118	19	118	10	65

Source: EY analysis of Marinus Link data

Sectors expected to accrue the largest share of value add (%)



Sectors that are expected to accrue the largest share of value add are power and utilities, finance and insurance services and construction.

Source: EY analysis of ABS data

Victoria - construction of Marinus Link

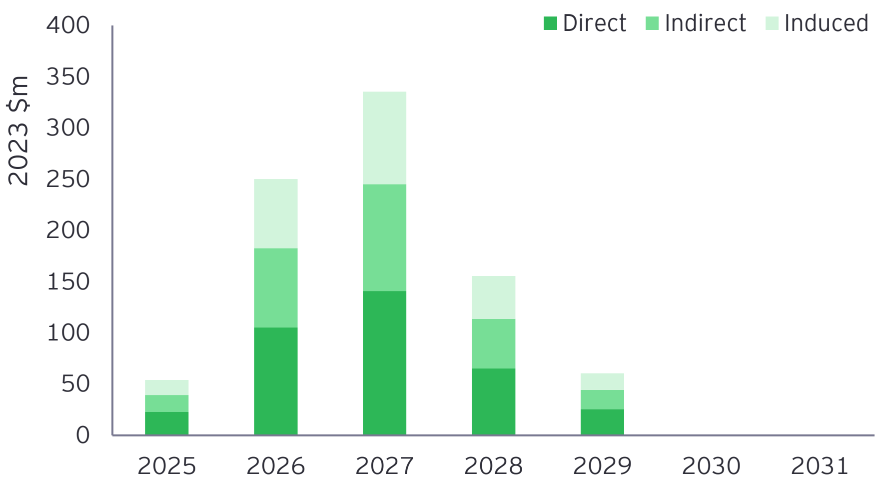
The construction cost of Marinus Link attributable to Victoria is estimated at $1,637 million for Stage 1 and $1,320 million for Stage 2. The peak year for construction is estimated to be in 2028.

Between 2025 and 2032, construction of Marinus Link Stage 1 is expected to support value add of $856 million (direct, indirect and induced) and while construction of Marinus Link Stage 2 is expected to support value add of $621 million (direct, indirect and indirect).

Between 2025 and 2032, construction of Marinus Link Stage 1 is expected to support 3,987 FTE years. Construction of Marinus Link Stage 2 is expected to support 2,894 FTE years.

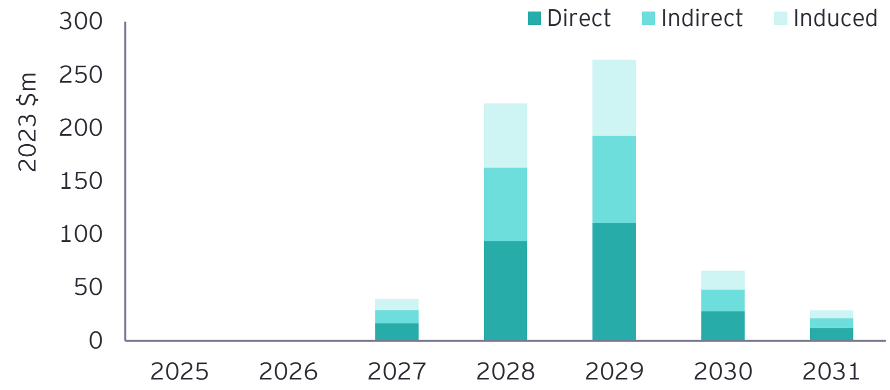
Overall, the construction of Marinus Link in Victoria is expected to support 1,456 direct and 5,425 indirect and induced FTE years.

Marinus Link - Stage 1 value add in Victoria



Source: EY analysis of Marinus Link data

Marinus Link - Stage 2 value add in Victoria



Source: EY analysis of Marinus Link data

FTE years supported in Victoria during construction of Marinus Link Stage 1 and Stage 2

	2025	2026	2027	2028	2029	2030	2031
Stage 1							
Direct	53	247	331	153	60	0	0
Indirect	109	505	677	314	122	0	0
Induced	89	414	555	257	100	0	0
Stage 2							
Direct			39	220	260	65	28
Indirect			80	450	533	133	58
Induced			65	370	437	109	47
Total							
Direct	53	247	370	373	320	65	28
Indirect	109	505	756	764	655	133	58
Induced	89	414	621	627	538	109	47

Source: EY analysis of Marinus Link data

Victoria - Marinus Link operations

The operations cost of Marinus Link Stage 1 and Stage 2 attributable to Victoria is estimated to be $7.5 million per stage, annually. Project Marinus is expected to be operational in 2030 and the results here have been modelled out to 2050 for both Stage 1 and Stage 2.

Operations cost of Project Marinus attributable to Victoria

	Marinus Link - Stage 1	Marinus Link - Stage 2
Period included	2030-2031	2030-2032
Annual operating cost attributable to Victoria (2023, $m)	8.4	8.4

Source: EY analysis of Marinus Link data

Operations of Marinus Link Stage 1 in Victoria is expected to support value add of $152 million and 513 FTE years.

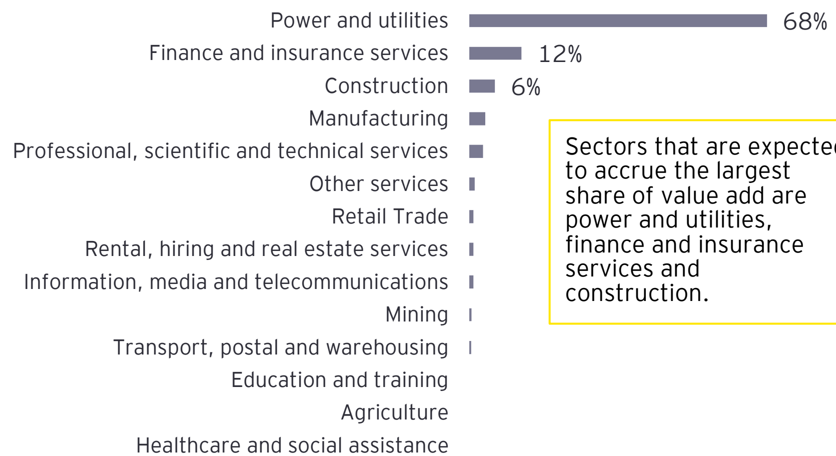
Operations of Marinus Link Stage 2 in Victoria is expected to support value add of $152 million and 513 FTE years.

Value add and FTE years supported in Victoria during operations of Project Marinus

	Marinus Link - Stage 1		Marinus Link - Stage 2	
	Value add (2023, $m)	FTE	Value add (2023, $m)	FTE
Annual				
Direct	3.0	5.9	3.0	5.9
Indirect	2.9	9.9	2.9	9.9
Induced	1.4	8.7	1.4	8.7
Total (2030-2050)				
Direct	62	124	62	124
Indirect	60	207	60	207
Induced	30	183	30	183

Source: EY analysis of Marinus Link data

Sectors expected to accrue the largest share of value add (%)



Sectors that are expected to accrue the largest share of value add are power and utilities, finance and insurance services and construction.

Source: EY analysis of ABS data

Project Marinus – peak construction FTE

During the peak construction period (2027 to 2029), Project Marinus is expected to support:

- 443 direct and 1,202 indirect and induced FTE years per year in Tasmania
- 354 direct and 1,320 indirect and induced FTE years per year in Victoria

FTE years supported in Tasmania during peak construction of Project Marinus

FTE years	2027	2028	2029	Total (2027-2029)	Total per year (2027 – 2029)
Stage 1					
Direct	331	153	60	544	181
Indirect	522	242	94	858	286
Induced	376	174	68	619	206
Stage 2					
Direct	39	220	260	519	173
Indirect	61	347	410	819	273
Induced	44	250	296	591	197
NWTD					
Direct	133	66	66	265	88
Indirect	210	104	104	417	139
Induced	151	75	75	301	100
Tasmania Total (Stage 1, Stage 2 and NWTD)	1,867	1,632	1,434	4,933	1,644

Source: EY analysis of Marinus Link data

FTE years supported in Victoria during peak construction of Project Marinus

FTE years	2027	2028	2029	Total (2027-2029)	Total per year (2027 – 2029)
Stage 1					
Direct	331	153	60	544	181
Indirect	677	314	122	1,113	371
Induced	555	257	100	913	304
Stage 2					
Direct	39	220	260	519	173
Indirect	80	450	533	1,063	354
Induced	65	370	437	872	291
Victoria Total (Stage 1 and Stage 2)	1,747	1,764	1,513	5,024	1,675

Source: EY analysis of Marinus Link data

FTE years supported in Tasmania and Victoria during peak construction of Stage 1 of Marinus Link (and NWTD)

FTE years	2025	2026	2027	Total (2025-2027)	Total per year (2025 – 2027)
Tasmania - Stage 1	197	917	1,229	2,342	781
Tasmania - NWTD	672	762	494	1,929	643
Tasmania Total (Stage 1 and NWTD)	869	1,679	1,723	4,271	1,424
Victoria Total (Stage 1)	251	1,166	1,563	2,980	993

Source: EY analysis of Marinus Link data

Tasmanian investments enabled by Project Marinus

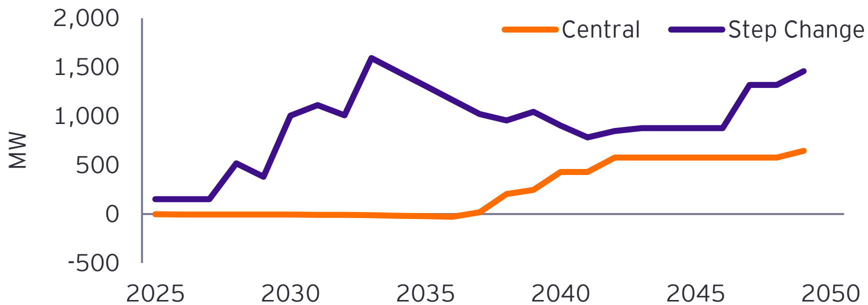
Overview of Tasmanian renewable energy projects enabled by Project Marinus

Project Marinus is expected to induce further renewable electricity generation in Tasmania to meet the growing demand for cleaner energy from the Australian electricity market. The installation magnitude (MW) and timeframe was estimated using EY's "market model", which forecasts generator dispatch and new builds. This modelling was included in the 2021 PACR submission and considers two AEMO 2020 Integrated System Plan scenarios:

- **Central –** this scenario reflects the transition of the energy industry under current policy settings and technology trajectories.
- **Step Change –** under this scenario Australia takes strong action on climate change. The national energy market (NEM) targets a 90% reduction in emissions from 2016 levels by 2050. In this scenario, aggressive global decarbonisation leads to faster technological improvements.

The analysis of induced investment in both scenarios was focused on the incremental capacity. That is, the resulting capacity in Tasmania over and above either the base case of no Marinus Link being installed, or result with Marinus Link. There are also differences in construction timelines with and without Marinus Link

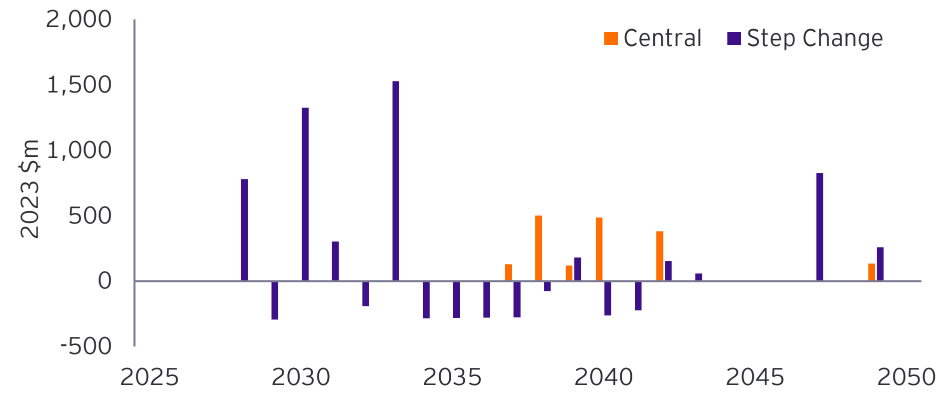
Incremental Tasmanian generation capacity, with Project Marinus vs. Base Case



Source: EY analysis of the 2021 PACR modelling submission

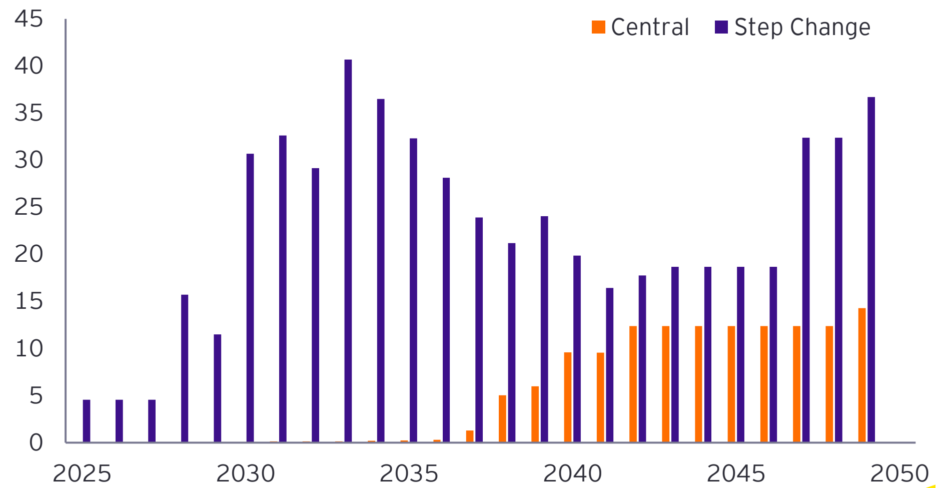
Note: When comparing the base case to the scenario with Marinus Link there is differences in both total capacity and construction timelines. When the base case builds capacity at a later date, the line above falls. When additional construction (over the base case) is built, the line rises.

Indicative capital costs for additional generation enabled by Project Marinus



Source: EY analysis of the 2021 PACR modelling submission

Indicative operating costs for additional generation enabled by Project Marinus



Source: EY analysis of the 2021 PACR modelling submission

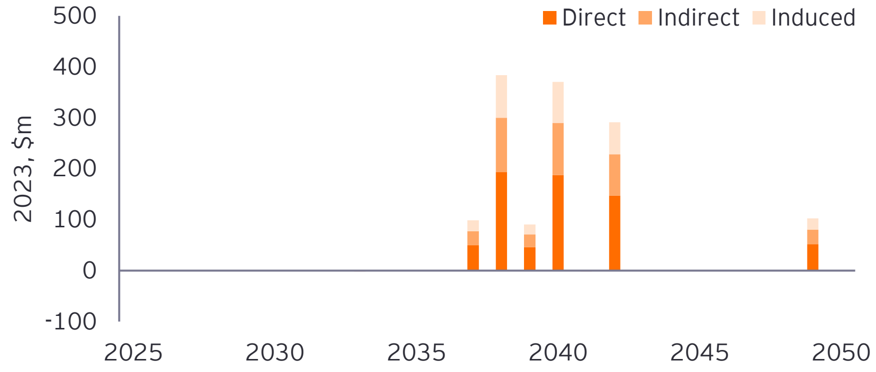
Tasmania – construction of renewable energy projects enabled by Project Marinus

Total construction cost of the renewable energy projects enabled by Project Marinus under the Central scenario is estimated at $1,744 million. The peak year for construction is estimated to be in 2038. Total construction cost of the renewable energy projects enabled by Project Marinus under the Step Change scenario is estimated at $3,573 million. The peak year for construction is estimated to be in 2033.

Under the Central scenario, construction is expected to support value add of $1,334 million (direct, indirect and induced). Under the Step Change scenario, construction is expected to support value add of $2,481 million (direct, indirect and induced).

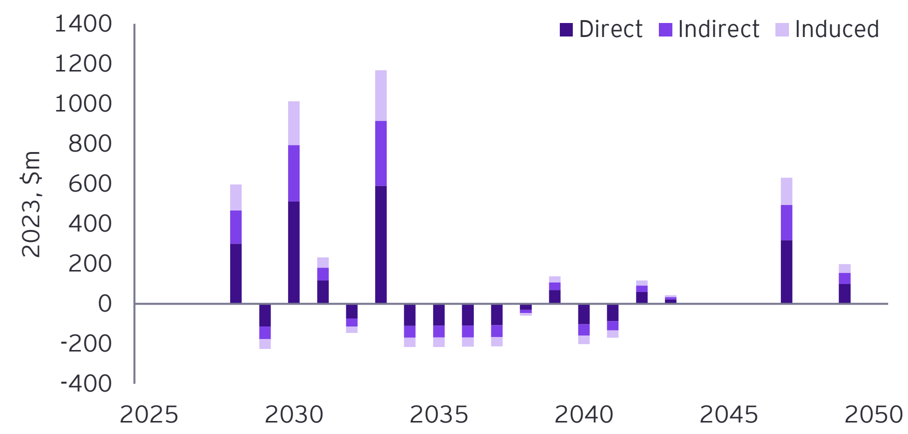
Under the Central and Step Change scenarios, renewable energy projects enabled by Project Marinus are expected to support 5,886 FTE years and 10,951 FTE years. Overall, under the Central scenario, the construction of additional renewable generation in Tasmania is expected to support 1,585 direct and 4,301 indirect and induced FTE years. While under the Step Change scenario the construction of additional renewable generation in Tasmania is expected to support 2,949 direct and 8,002 indirect and induced FTE years.

Value add during construction of renewable energy projects in Tasmania – Central scenario



Source: EY analysis of the 2021 PACR modelling submission

Value add during construction of renewable energy projects in Tasmania – Step Change scenario



Source: EY analysis of the 2021 PACR modelling submission

FTE years supported in Tasmania during construction of renewable energy projects enabled by Project Marinus, by scenario

	2025-2030	2031-2035	2036-2040	2041-2045	2046-2050
Central					
Direct	1	-3	1,120	345	122
Indirect	1	-5	1,767	543	192
Induced	1	-3	1,274	392	139
Step Change					
Direct	1,647	978	-651	-11	986
Indirect	2,597	1,542	-1,026	-18	1,554
Induced	1,873	1,113	-740	-13	1,121

Source: EY analysis of the 2021 PACR modelling submission

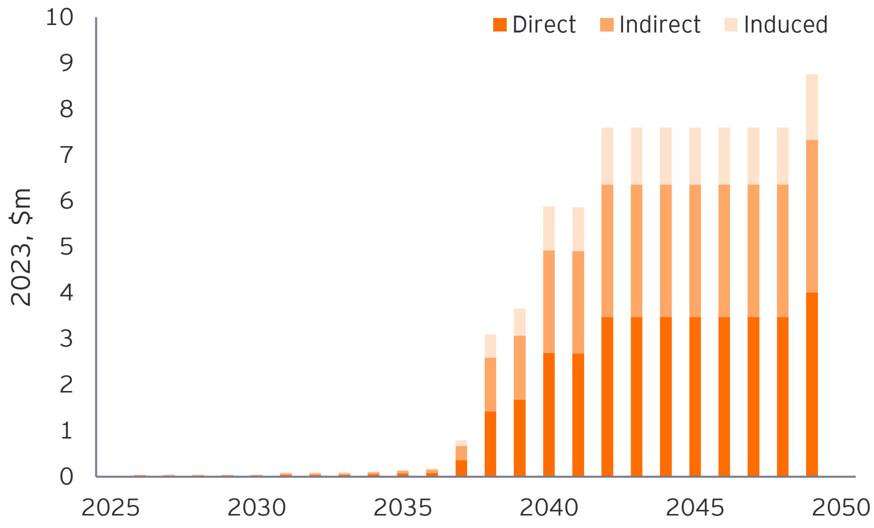
Tasmania - operations of renewable energy projects enabled by Project Marinus

The operations cost (out to 2050) of the renewable energy projects enabled by Project Marinus under the Central scenario is estimated to be $134 million. The operations cost (out to 2050) of the renewable energy projects enabled by Project Marinus under the Step Change scenario is estimated to be $573 million.

Under the Central and Step Change scenarios, the operations of additional renewable energy projects in Tasmania are expected to support value add of $73 million and $31 million (direct, indirect and induced).

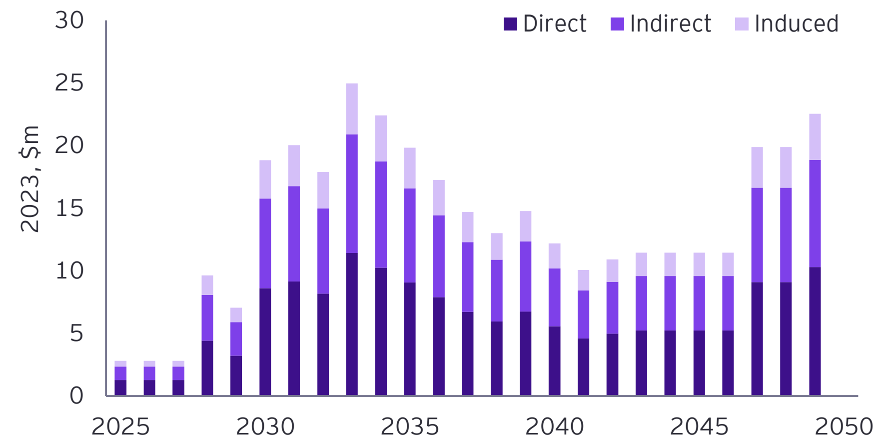
Central scenario is expected to support and 248 FTE years, while the Step Change scenario is expected to support 1,058 FTE years.

Value add during operations of renewable energy projects in Tasmania – Central scenario



Source: EY analysis of the 2021 PACR modelling submission

Value add during operations of renewable energy projects in Tasmania – Step Change scenario



Source: EY analysis of the 2021 PACR modelling submission

FTE years supported in Tasmania during operations of renewable energy projects enabled by Project Marinus, by scenario

	2025-2030	2031-2035	2036-2040	2041-2045	2046-2050
Central					
Direct	0	0	9	23	20
Indirect	0	1	19	49	43
Induced	0	1	14	37	32
Step Change					
Direct	28	67	46	35	47
Indirect	60	144	98	76	101
Induced	45	107	73	56	75

Source: EY analysis of the 2021 PACR modelling submission

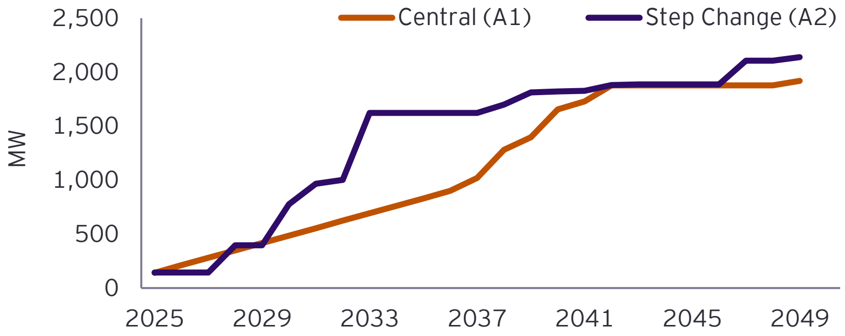
Tasmania - construction of renewable energy projects enabled by Project Marinus - **alternate scenarios**

The renewable energy investments identified by the PACR energy market modelling assume that any announced construction or policy positions (e.g. the 200% Tasmanian renewable energy target) are met in the base case (i.e., without Marinus Link). This assumption may be conservative and does not recognise how many new projects will be planning to sell excess capacity into Victoria using the Marinus Link, and will thus be unlocked due to the development of the Marinus Link project.

To represent an upper bound of enabled projects, we have estimated alternate versions of the Central and Step Change scenarios where only half of all new wind generation in Tasmania (as identified in the PACR modelling) would go ahead in the absence of Marinus Link. The amount of pumped hydro generation capacity remains the same as in the original scenarios.

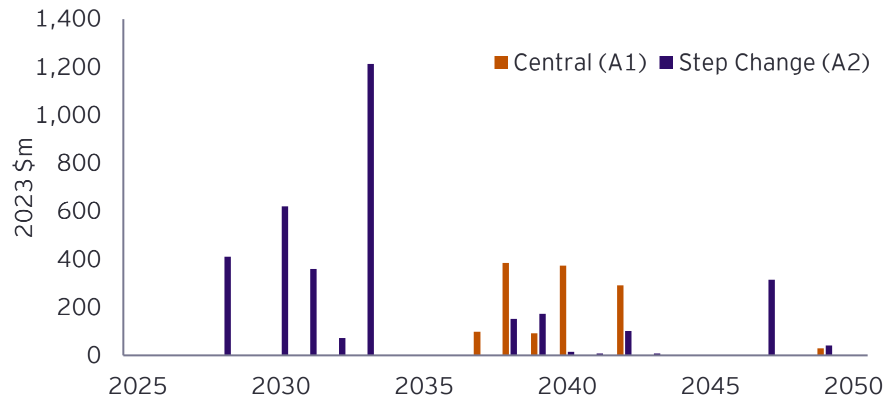
Under the alternate Central and alternate Step Change scenarios, construction of renewable energy projects enabled by Marinus Link results in total value add of $1,271 million and $3,496 million. The alternate Central scenario is also expected to support 5,611 total FTE years. While the alternate Step Change scenario, construction of renewable energy projects enabled by Marinus Link is expected to support 15,429 total FTE years.

Incremental Tasmanian generation capacity, with Project Marinus vs. Base Case, assuming 50% of all new wind capacity is enabled by Marinus Link



Source: EY analysis of the 2021 PACR modelling submission

Total value add during construction of renewable energy projects in Tasmania by alternate scenario



Source: EY analysis of the 2021 PACR modelling submission

FTE years supported in Tasmania during construction of renewable energy projects enabled by Project Marinus, by alternate scenario

	2025-2030	2031-2035	2036-2040	2041-2045	2046-2050
Central (A1)					
Direct	0	0	1,128	346	36
Indirect	0	0	1,779	546	57
Induced	0	0	1,283	394	41
Step Change (A2)					
Direct	1,227	1,956	404	141	425
Indirect	1,934	3,084	638	223	671
Induced	1,396	2,225	460	161	484

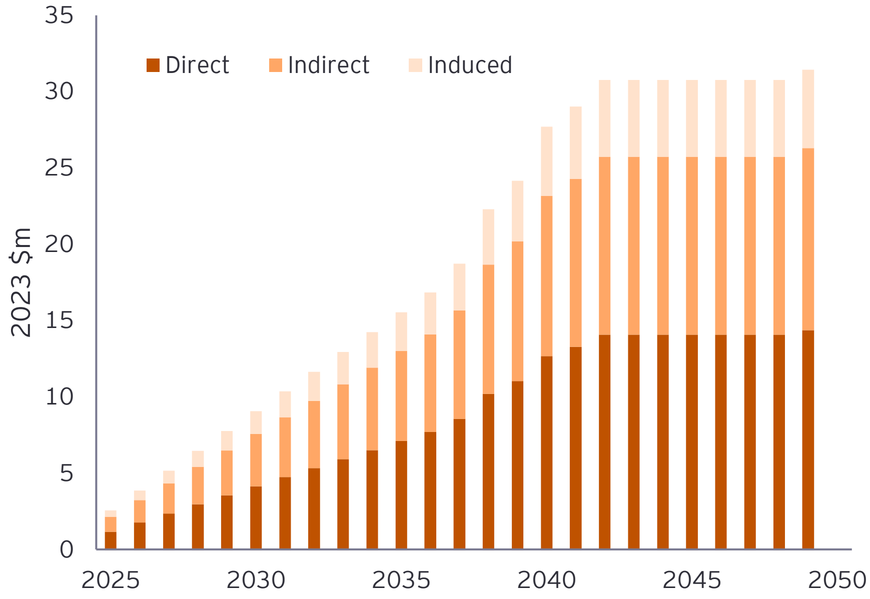
Source: EY analysis of the 2021 PACR modelling submission

Tasmania – operations of renewable energy projects enabled by Project Marinus – **alternate scenarios**

Under the alternate Central scenario, operations of renewable energy projects enabled by Marinus Link is expected to result in total value add of $485 million, which grows to $556 million under the alternate Step Change scenario.

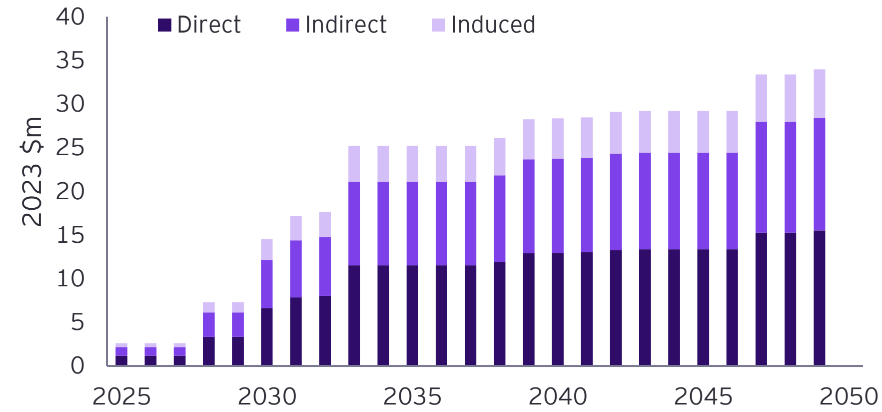
Under the alternate Central and alternate Step Change scenario, operations of renewable energy projects enabled by Marinus Link are expected to result in 1,466 and 1,680 total FTE years.

Value add during operations of renewable energy projects in Tasmania – Central (A1) scenario



Source: EY analysis of the 2021 PACR modelling submission

Value add during operations of renewable energy projects in Tasmania – Step Change (A2) scenario



Source: EY analysis of the 2021 PACR modelling submission

FTE years supported in Tasmania during operations of renewable energy projects enabled by Project Marinus, by alternate scenario

	2025-2030	2031-2035	2036-2040	2041-2045	2046-2050
Central (A1)					
Direct	22	41	70	97	79
Indirect	48	88	150	208	169
Induced	35	66	111	155	126
Step Change (A2)					
Direct	24	71	85	93	83
Indirect	51	151	182	198	177
Induced	38	112	135	148	132

Source: EY analysis of the 2021 PACR modelling submission

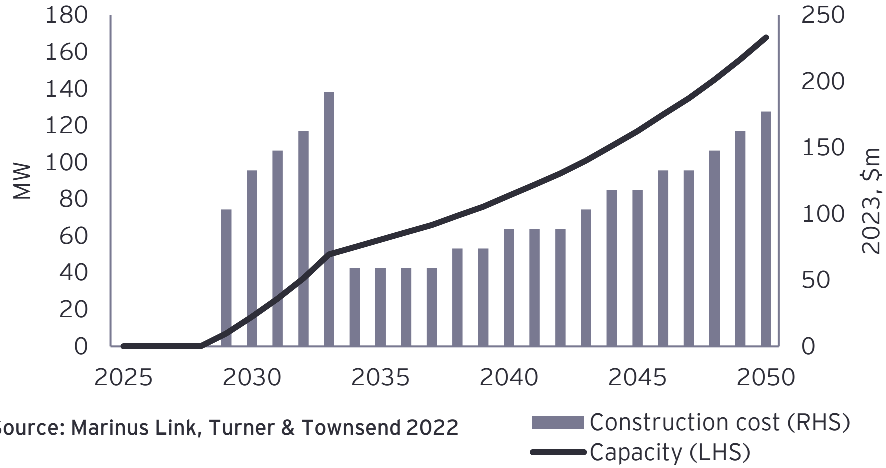
Tasmania - construction of additional data centre capacity enabled by Project Marinus

Project Marinus is also expected to enable telecommunications investment for Tasmania. This investment has been quantified (in terms of MW of additional data hub capacity) and provided to EY by Marinus Link. The calculation is included in Appendix D. These results consider the economic contribution of the construction of additional data centre capacity in Tasmania as a result of Project Marinus.

Total construction cost of the additional data centre capacity enabled by Project Marinus is estimated at $2,483 million. We have not modelled operating costs from the data centres enabled by Project Marinus. Typically the operating cost of a data centre is around 95% electricity, the contribution of which is already counted as part of the additional renewable energy projects,

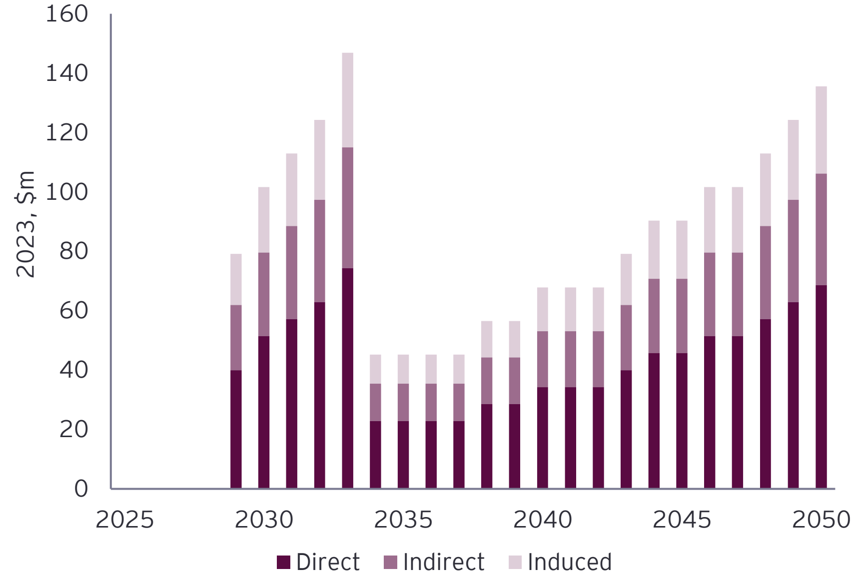
Construction is expected to support value add of $1,899 million (direct, indirect and induced) and 8,380 FTE years. Overall, the construction of additional data centre capacity in Tasmania is expected to support 2,256 direct and 6,124 indirect and induced FTE years.

Additional Data Centre Capacity (and associated capital costs) enabled by Project Marinus



Source: Marinus Link, Turner & Townsend 2022

Value add during construction of additional data centre capacity in Tasmania

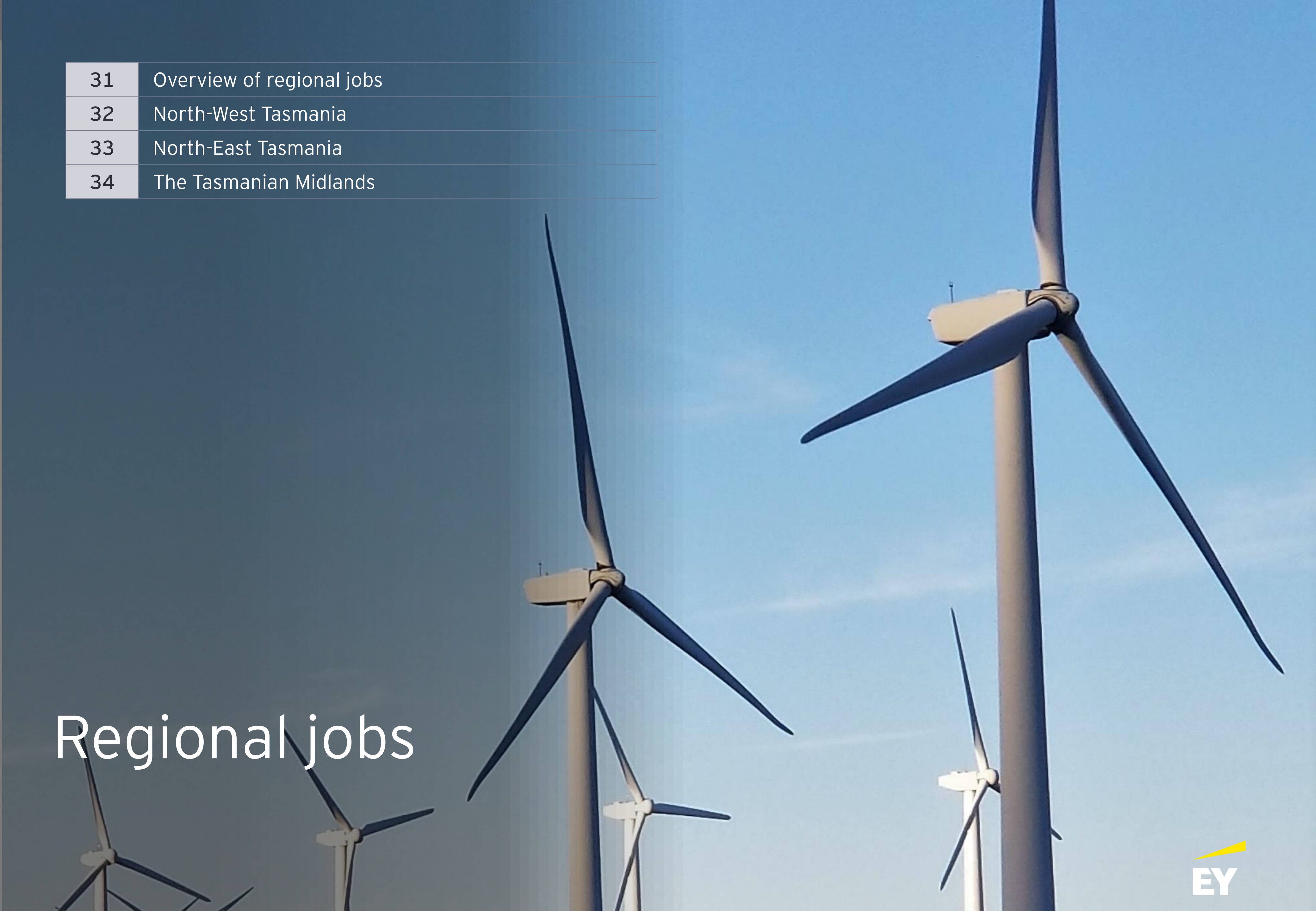


Source: EY analysis of Marinus Link data

FTE years supported in Tasmania during construction of additional data centre capacity enabled by Project Marinus

	2025-2030	2031-2035	2036-2040	2041-2045	2046-2050
Direct	215	564	322	470	685
Indirect	339	889	508	741	1,080
Induced	244	642	367	535	779

Source: EY analysis of Marinus Link data



Regional jobs

Overview of regional jobs

Many local economies are expected to benefit from the construction and operations of Project Marinus and the enabled renewable energy projects. The contribution of Marinus Link is modelled in North West Tasmania but it is likely that some would flow state-wide. This section considers the employment impacts on North-West Tasmania, North-East Tasmania and the Tasmanian Midlands.

In order to capture the total direct and indirect economic contribution of Marinus Link and the induced investment to these regions, the analysis attributes the expected increase in generation capacity to each region. The methodology used to estimate this apportionment can be found in Appendix C. These results are broken down and discussed on the next three pages.

Total FTE attributable to each region[1] for construction and operations of Project Marinus and enabled renewable energy projects

	Marinus Link	North-West Transmission Developments	Renewable energy projects enabled by Project Marinus	
			Central	*Step Change*
North-West Tasmania				
Construction	4,923	2,201	5,152	10,618
Operations	80	17	1,311	1,888
North-East Tasmania				
Construction			-4,249	-4,666
Operations			-962	-787
The Tasmanian Midlands				
Construction			2,500	4,453
Operations			165	725

Source: EY analysis of the 2021 PACR modelling submission and Marinus Link data

1. The FTE expected to be attributable to each region do not add up to the total jobs expected for the whole of Tasmania (as quoted earlier in this report) This is driven by construction and operating jobs flowing to regions not captured in the regional investment analysis, which are represented by the unshaded areas in the map to the right.

Indicative renewable investment locations in Tasmania

Source: TasNetworks

North-West Tasmania

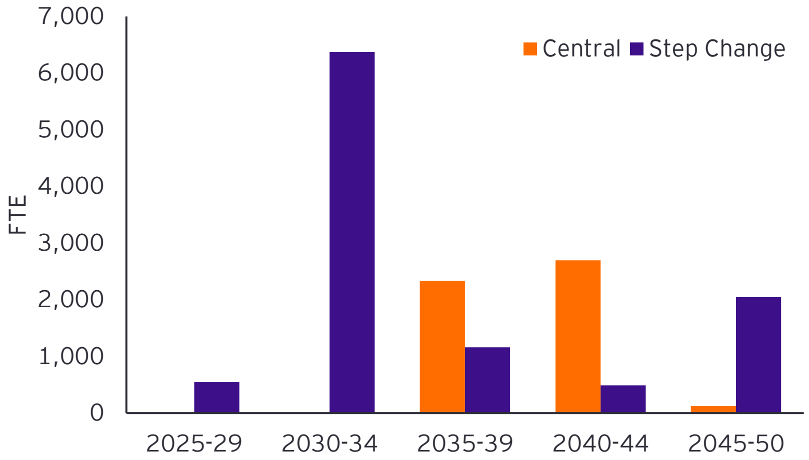
North-West Tasmania is renowned for its high quality national parks and nature reserves. The indicative Tasmanian connection point of Marinus Link is located in the Burnie area, a town in North-West Tasmania. As such, Marinus Link is expected to support construction and operations jobs in the region.

North-West Tasmania is identified as a location for potential pumped hydro and wind generation capacity enabled by Project Marinus.

Construction of Project Marinus is expected to support 4,923 FTE years in North-West Tasmania, with between 5,152 and 10,618 additional FTE supported as a result of the construction of renewable generation capacity (depending on the scenario).

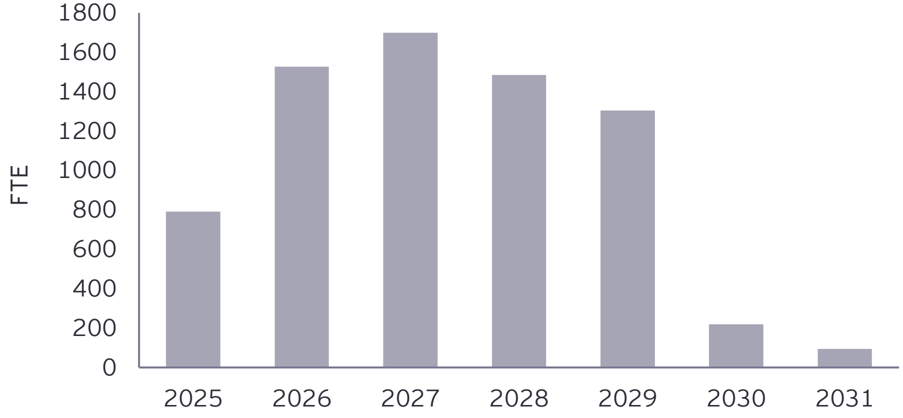
The operations of Project Marinus are expected to support 80 FTE in North-West Tasmania, while between 1,311 and 1,888 operations FTE are expected to result from renewable energy generation enabled by Project Marinus.

FTE years supported in North-West Tasmania during construction of renewable energy projects enabled by Project Marinus



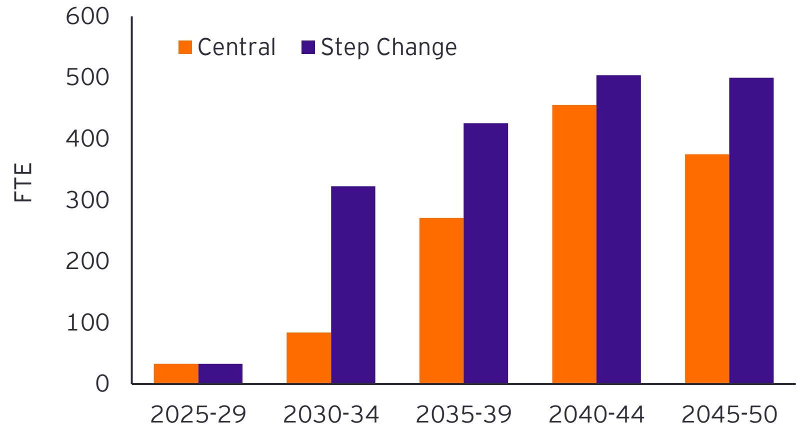
Source: EY analysis of the 2021 PACR modelling submission

FTE years supported in North-West Tasmania during construction of Project Marinus



Source: EY analysis of Marinus Link data

FTE years supported in North-West Tasmania during operations of renewable energy projects enabled by Project Marinus



Source: EY analysis of the 2021 PACR modelling submission

North-East Tasmania

North-East Tasmania is characterised by its rich arts and cultural heritage and diverse natural landscape. North-East Tasmania has already been identified as a suitable location for increased wind generation capacity.

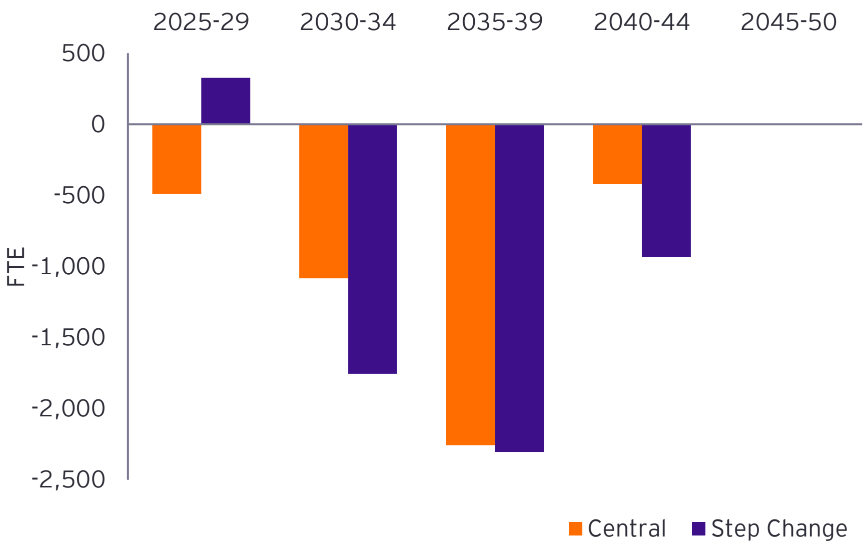
However, according to the PACR modelling Project Marinus shifts capacity away from North-East Tasmania and into Nort-West, resulting in reductions in construction and operations FTE under both the Central and Step Change scenarios.

Reduction in total FTE attributable to North-East Tasmania based on a redistribution of generation capacity enabled by Project Marinus

	Renewable energy projects enabled by Project Marinus	
	Central	*Step Change*
North-East Tasmania		
Construction	-4,249	-4,666
Operations	-962	-787

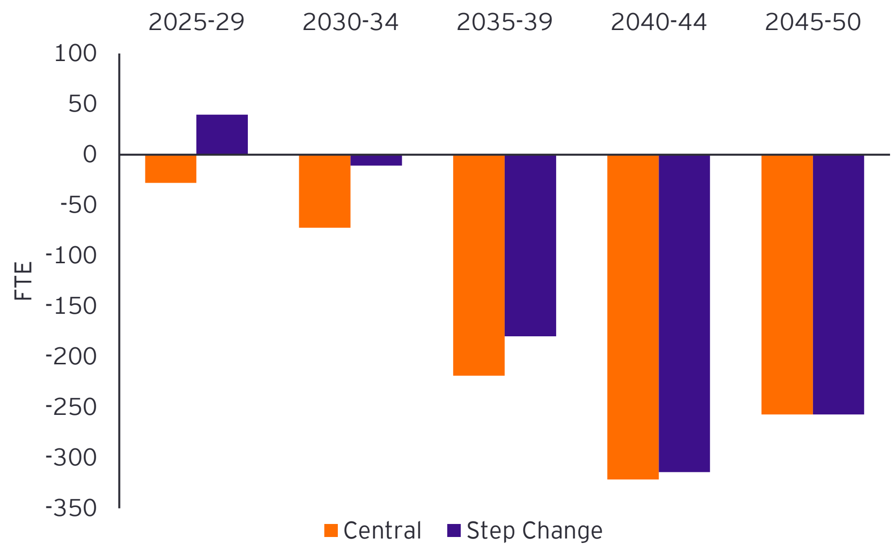
Source: EY analysis of the 2021 PACR modelling submission

Reduction in FTE years in North-East Tasmania due to lost construction of renewable energy projects



Source: EY analysis of the 2021 PACR modelling submission

Reduction in operational FTE years in North-East Tasmania due to a reduction in generation capacity



Source: EY analysis of the 2021 PACR modelling submission

The Tasmanian Midlands

The Tasmanian Midlands is replete with prominent national parks and excellent natural resources. The Tasmanian Midlands have been identified as a location for potential pumped hydro and wind generation capacity enabled by Project Marinus.

Under the Central scenario, construction of additional generation capacity supports 2500 FTE years between 2025 and 2050.

Under the Step Change scenario, construction of additional generation capacity supports 4,453 FTE years between 2025 and 2050.

Under the central scenario, operations of the additional generation supports 165 FTE years, while under the Step Change scenario this becomes 725 FTE years.

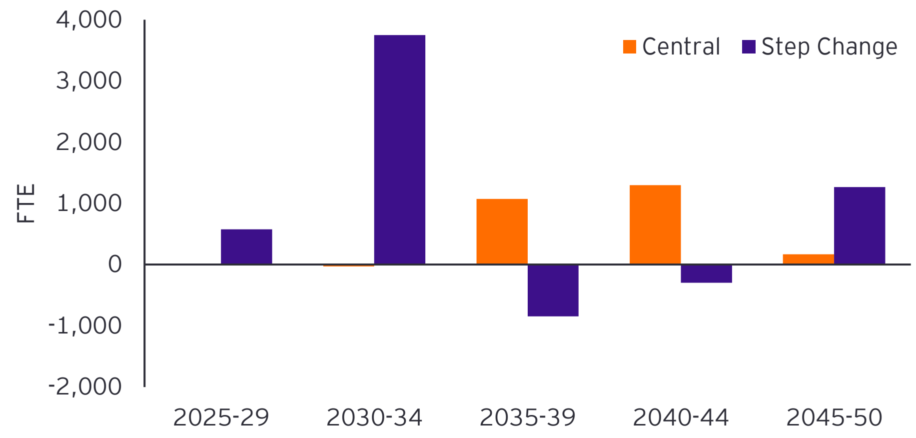
Under the Step Change scenario, there are some negative FTE values between 2035 and 2044. This represents shifting construction timelines with and without Marinus Link. Under the Step Change scenario, with Marinus Link there are more FTE years supported between 2030 and 2034 due to earlier construction timelines. In contrast, between 2035 and 2039, there is less construction with Marinus Link when compared to the base case (without Marinus Link).

FTE years supported in the Tasmanian Midlands by renewable energy projects enabled by Project Marinus

	Renewable energy projects enabled by Project Marinus	
	Central	*Step Change*
The Tasmanian Midlands		
Construction	2,500	4,453
Operations	165	725

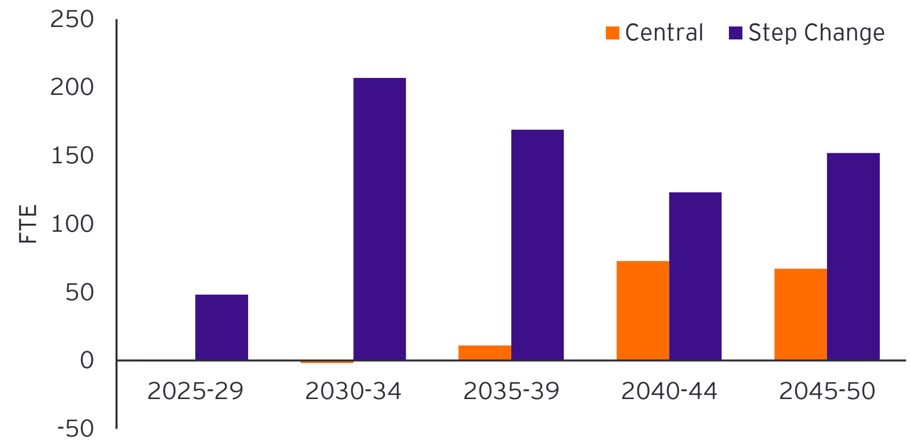
Source: EY analysis of the 2021 PACR modelling submission

FTE years supported in the Tasmanian Midlands during construction of renewable energy projects enabled by Project Marinus

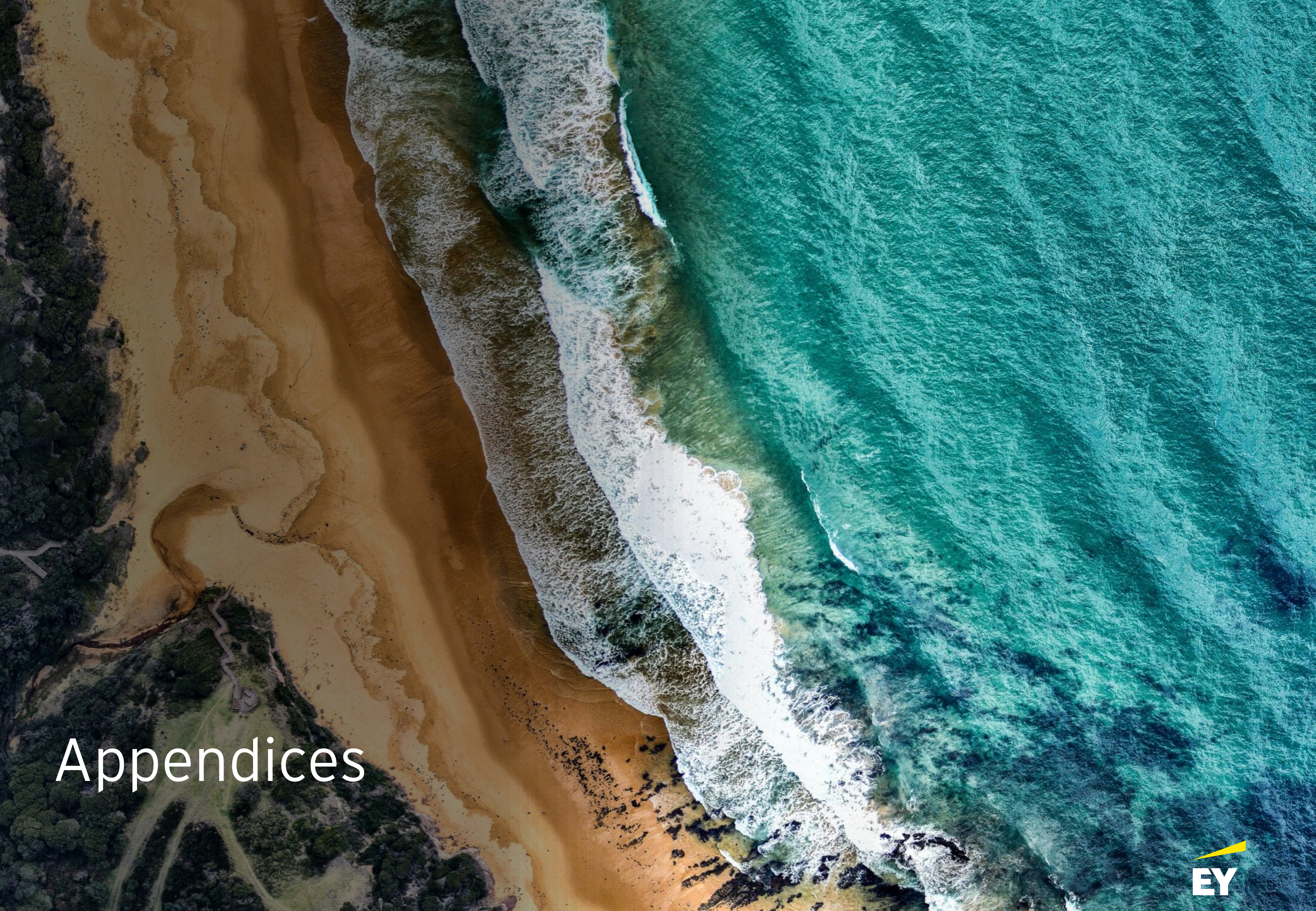


Source: EY analysis of the 2021 PACR modelling submission

FTE years supported in the Tasmanian Midlands during operations of renewable energy projects enabled by Project Marinus



Source: EY analysis of the 2021 PACR modelling submission



Appendices

Glossary

Term	Description
Direct economic contribution	Total revenues generated by an industry, plus any applicable value-add taxes
Economic contribution	The total direct effects of an industry (revenue plus any value-add taxes), plus the flow-on (indirect) effects. The flow-on effects are captured by applying an economic multiplier. It is important to note that economic contribution is a gross measure rather than a net measure of the contribution of an industry. Economic contribution studies do not consider substitution impacts, or what would happen if the relevant industry ceased to exist
Gross Output	Market value of goods and services produced
Value Add	Market value of goods and services produced, after deducting the cost of goods and services used. This represents the sum of all wages, income and profits generated
Direct effect	The direct impact resulting from the construction and operation of Marinus Link
Indirect effect	Flow-on (Indirect) contribution generated by an industry as it purchases input goods and services generating revenue for other businesses
Induced (or consumption) effect	Flow-on (Indirect) contribution generated by an industry as its employees spend their wages and salaries on household consumption, providing revenue for other businesses
Economic multiplier	Used to estimate the total economic contribution of an industry by multiplying the direct contribution. The economic multiplier incorporates the additional economic contribution generated by the 'Direct' economic contribution, which is the sum of the industrial effect and the consumption effect
Employment contribution	The total direct employment effects of an industry (total employees), plus the flow-on (indirect) effects. The flow-on effects are captured by applying an employment multiplier
Employment multiplier	Used to estimate the total economic contribution of an industry by multiplying the direct contribution. The employment multiplier incorporates the additional employment contribution generated by the 'Direct' employment contribution
FTE years	An 'FTE-year' represents one full time equivalent role supported for a full year – for instance, 1,000 FTE-years may be 500 FTE sustained over 2 years, or 100 FTE sustained over 10 years.

Appendix A – Regional input-output multiplier calculations

Economic contribution analysis measures market related direct and indirect expenditure and economic activity generated by a specific industry and/or activity. This is done by using Input-Output (IO) multipliers. To assess the regional impacts, the Australian IO table must be disaggregated and then used for the multiplier calculation.

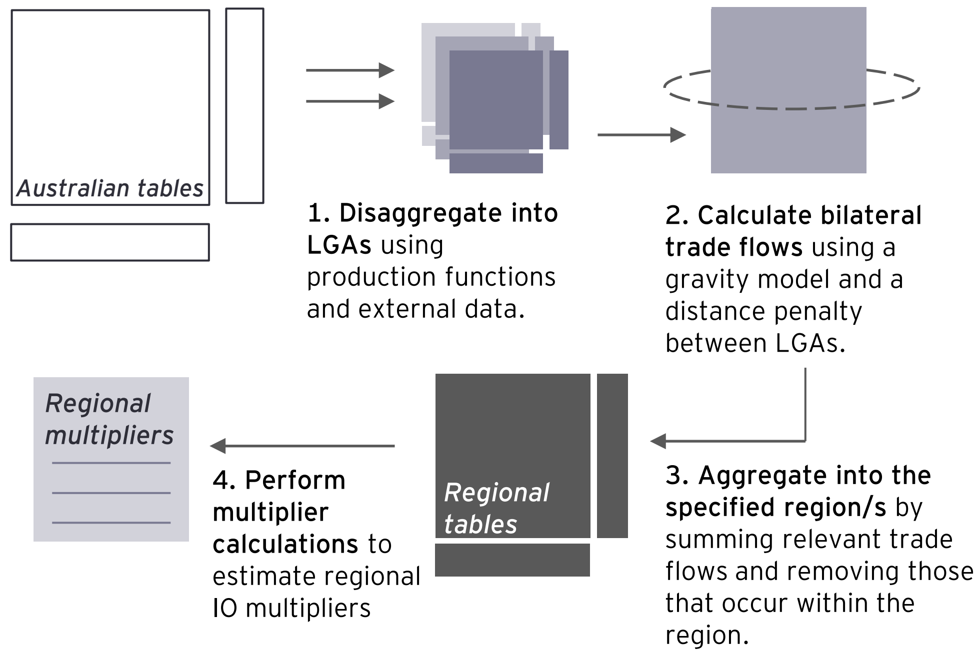
Methodology for calculating regional input-output multipliers

1. Disaggregate the Australian table into local government areas (LGAs) using production functions along with the following splits:
    - A. Industry output is split by LGA/Input-Output Industry Group (IOIG) sector employment data.
    - B. Industry demands are determined by the commodity output combined with production functions.
    - C. Household and Government consumption is split according to the LGA population.
    - D. Commodity usage for capital formation is split according to Gross Regional Product (GRP).
    - E. Foreign imports/exports and inventories are split according to production shares.
    - F. Domestic imports/exports are set to zero and solved using the gravity model.
2. Calculate the bilateral trade flows utilising a gravity model and a penalty matrix made using the distances between LGAs. The greater the distance, the lower the trade flows, all else equal.
3. To aggregate the specified region containing several LGAs, the model procedure adds up the individual LGA tables and removes trade that occurs between LGAs within the region.
4. Calculate regional IO multipliers using regional tables.

Data Sources

- **Australian National Accounts: Input-Output Tables for 2020-21 -** Table 2 and 3
- **Australian Bureau of Statistics (ABS)** - Employment for each LGA by Input-Output Industry Group (IOIG)

Regional input-output multiplier calculations



Appendix B - Project Marinus cost apportionment methodology

Marinus Link provided EY with a construction and operations cost breakdown, including items split within the following broad cost categories:

- Cable costs;
- Substation costs;
- Network integration costs; and
- Project costs.

These cost items did not refer to a specific geographic location. EY has split them 50/50 between Victoria and Tasmania, as directed by Marinus Link. The tables below summarise this approach.

Indicative high-level construction costs, 2025 onwards ($m, real 2023 AUD)

	Tasmania	Victoria
Stage 1	1,637	1,637
Stage 2	1,320	1,320
NWTD	810	-
TOTAL	3,767	2,957

Source: EY analysis of Marinus Link data

Marinus Link provided EY with ongoing operations costs for both Stage 1 and 2. These have also been apportioned equally between Tasmania and Victoria.

Indicative annual operating costs ($m, real 2023 AUD)

	Tasmania	Victoria
Stage 1	8.4	8.4
Stage 2	8.4	8.4
NWTD	4.6	-
TOTAL	21.4	16.8

Source: EY analysis of Marinus Link data

This analysis assumes that the cables are internationally sourced. Therefore, equipment costs have not been included in the economic contribution calculation (see table directly below). The total value of equipment has been assumed based on the percentage of spend on equipment included in the 2019 report.

Construction cost, 2025 onwards ($m, real 2023 AUD) attribution

Cost category	Tasmania	Victoria
Total cost apportioned to each region	3,767	2,957
Internationally sourced equipment	1,447	1,354
Cost of Project Marinus used in this analysis	2,319	1,603

Source: EY analysis of Marinus Link data

Appendix C – Estimating Tasmanian renewable energy projects enabled by Project Marinus

Marinus Link is expected to enable investment in further renewable electricity generation in Tasmania to meet the growing demand for cleaner energy from the NEM. For the analysis in this report EY used the installation magnitude (MW) and timeframe of additional investment in Tasmania from the 2021 PACR submission by EY's market modelling team. The impacts to any other state in Australia were not considered. The analysis in this report considers two of the AEMO 2020 Integrated System Plan scenarios:

- **Central –** this scenario reflects the transition of the energy industry under current policy settings and technology trajectories.
- **Step Change –** under this scenario Australia takes strong action on climate change. The national energy market (NEM) targets a 90% reduction in emissions from 2016 levels by 2050. In this scenario, aggressive global decarbonisation leads to faster technological improvements.

Any changes to capacity are presented as the marginal effects of Marinus Link on the base case, which already considers for capacity expansion and investment. As a result any negative amounts across the time series are caused by construction occurring in the base case that would be brought forward and accelerated with Marinus Link.

Operating costs are annual payments based on the amount of capacity installed. Some negative operating costs were modelled, as they were either a result of:

- Less physical capacity installed overall compared to the No Marinus Case for certain technologies
- Less physical capacity installed in some years compared to the No Marinus Case, despite the overall capacity remaining unchanged for certain technologies.

Summary of physical capacity and construction costs in Tasmania enabled by Project Marinus

	Difference in physical capacity in 2050 (MW)	Total construction cost (2022 – 2050, $m)
Central		
Wind	0	73
Pumped Hydro	645	1,484
Step Change		
Wind	583	1,152
Pumped Hydro	876	2,037

Regional jobs

The below table outlines the distribution of energy technology between regions in Tasmania. Pumped Hydro has been evenly split between North West Tasmania and the Tasmanian Midlands due to the expected distribution of AEMO scenario assumptions. Wind technology will be expanded across the various Renewable Energy Zones in North West, North East and Midland Tasmania, leading to the allocation shown below.

Proportions of each generation technology type from AEMO ISP data

	North West Tasmania	North-East Tasmania	The Tasmanian Midlands
Pumped Hydro	50%	-	50%
Wind	33%	33%	33%

1. Note that numbers have been rounded for ease of reference

Source: EY analysis of AMEO data

Appendix D – Estimating construction of additional data centre capacity in Tasmania enabled by Project Marinus

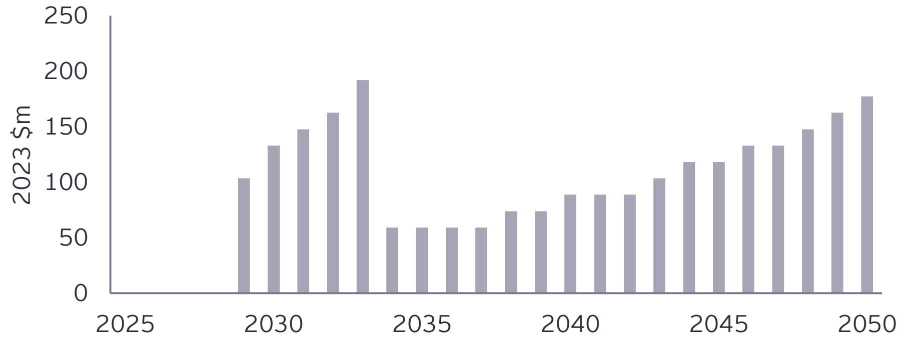
Project Marinus is expected to unlock telecommunications benefits in Tasmania, based on the growing demand for data centre capacity across Australia. Marinus Link provided EY with information about additional data centre capacity in Tasmania as a result of Project Marinus. EY did not consider any outflows of data centre capacity from Victoria

The Turner & Townsends, Data Centre Cost Trends Report, (2022) was used to calculate an estimate of total capital expenditure based on the capacity figures provided by Marinus Link. As Tasmania was not included in the report, the construction cost per watt of data centre capacity for Melbourne was used to estimate construction costs.

Cost per watt of data centre capacity in Melbourne = **$8.8 USD**

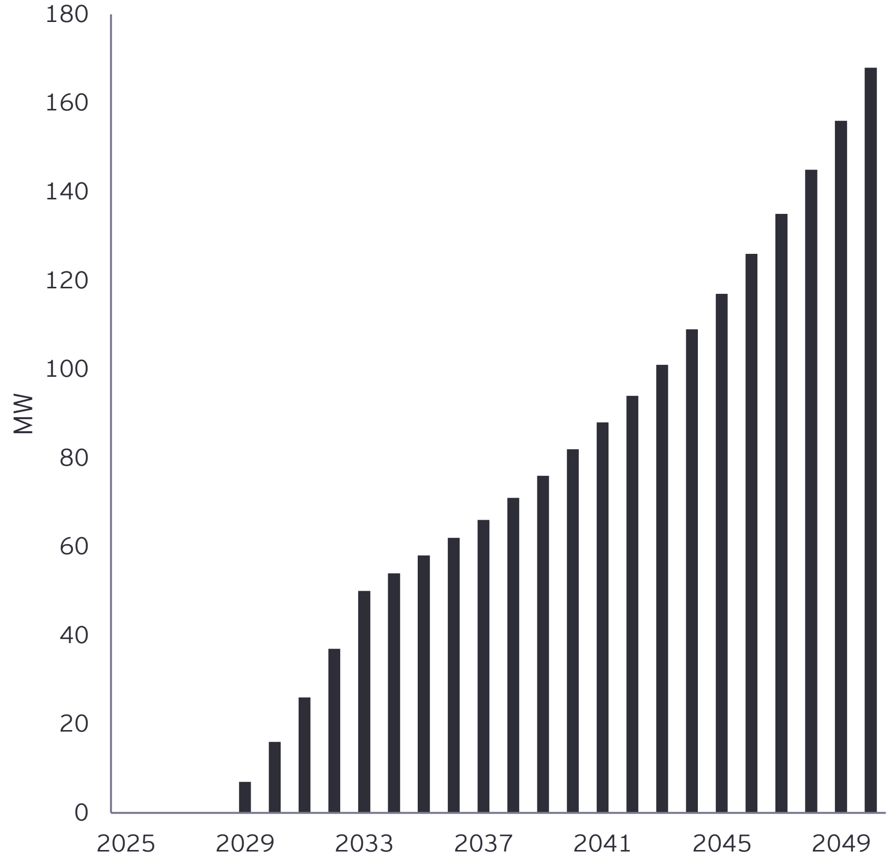
Multipliers were then applied to construction costs to determine value add and FTE years supported. We have not modelled operating costs from the data centres enabled by Project Marinus. Typically the operating cost of a data centre is around 95% electricity, the contribution of which is already counted as part of the additional renewable energy projects,

Construction cost of additional data centre capacity in Tasmania



Source: EY analysis of Marinus Link and Turner & Townsend data

Additional data centre capacity in Tasmania enabled by Project Marinus



Source: EY analysis of Marinus Link data

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How do customers benefit from Project Marinus?

Summary Report 2024

This document has been produced by Marinus Link Pty Ltd and Tasmanian Networks Pty Ltd, ABN 24 167 357 299 (hereafter referred to as "TasNetworks").

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1. Summary

In late 2023, Marinus Link Pty Ltd (**MLPL**) engaged independent global consulting firm, FTI Consulting LLP (**FTI**), to consider the impact that Project Marinus is expected to have on customers across the National Electricity Market (**NEM**). This represents an update to a similar study carried out by FTI in 2020 and is being undertaken due to the significant changes in NEM forward outlook that have occurred in the last 3 years. Both studies have focussed on customer benefits: how Project Marinus would affect the electricity prices that customers pay compared to a counterfactual case 'without Project Marinus'.

Conclusions and implications

FTI's updated analysis of customer benefits is based on market modelling, using inputs, assumptions and policy scenario settings that are broadly consistent with the Australian Energy Market Operator (**AEMO**) 2023 Inputs, Assumptions and Scenarios Report (IASR), focussing on the Step Change scenario. Key findings and implications are:

- Consistent with FTI's previous customer benefits analysis, FTI's latest study indicates that Project Marinus is expected to materially reduce wholesale prices in all NEM regions. The largest average wholesale price reductions during the 2031-50 study period occur in Tasmania ($20-22/MWh reduction[1]) and Victoria ($17-20/MWh reduction).
    - Project Marinus provides material downward pressure on wholesale prices due to the additional Tasmanian generation it unlocks (high quality wind and pumped hydro resources, as well as better access to the existing hydro fleet), coupled with the benefit of displacing higher-priced generation (largely gas-fired generation and demand response).
    - The effect of the reduction in wholesale electricity prices is expected to equate to an annual $148 to $165 reduction in the wholesale energy element of customer energy bills in Tasmania and $70 to $78 in Victoria relative to the Without Project Marinus counterfactual. Project Marinus is also expected to reduce wholesale energy element of customer energy bills in all the other regions of the NEM.
- FTI's updated assessment estimates net customer benefits[2] from Project Marinus to be $10.0-12.5 billion[1] over the study period of 2031-2050.

[1] Range is based on results across 2 different scenarios; more details on these scenarios is provided later in this report.

[2] Net customer benefits are calculated as the gross customer benefit arising from lower wholesale cost minus Project Marinus cost and interconnector residues.

- Net customer benefits have increased relative to the 2020 study, which estimated net customer benefits of $5.4 billion (in 2020 dollars)[3]. Changes in the forward outlook since 2020 include more rapid exit of coal-fired generation, faster entry of renewable generation and higher fuel costs (reflecting changing market conditions and inflation).

2. Purpose and scope of this report

The purpose of this summary report is to provide a high-level summary of the results of modelling work undertaken by FTI consultants[4] on behalf of MLPL, which assesses how NEM customers would benefit if Project Marinus proceeds. FTI's report is published alongside this summary report and provides more details on the inputs, assumptions, methodology and results of their study.

This work represents an update to a similar assessment carried out by FTI in 2020 and is being undertaken due to the significant changes in NEM forward outlook that have occurred in the last 3 years. In particular, the rapid transformation taking place across the NEM means that many of the input assumptions adopted in the 2020 study – including expected government policies, market developments (including the timing of coal plant closures), and new generation/storage projects – no longer reflect the latest available information.

FTI's modelling approach differs in two respects from the analysis presented in our 2021 Project Marinus Project Assessment and Conclusions Report (PACR)[5] and AEMO's Integrated System Plan,:

- FTI focuses exclusively on the impact of Project Marinus on customers, rather than also considering the impact on other market participants, i.e. generators, across the NEM; and
- FTI's modelling takes account of generators' likely bidding behaviour, rather than assuming that generators' bids will always reflect their marginal costs.

Specifically, FTI's modelling approach is targeted to address the question of whether and how much customers can expect to be better off through reduced wholesale electricity prices if Project Marinus proceeds compared to a situation in which it does not. This analysis differs from the Regulatory Investment Test for Transmission (**RIT-T**), which considers the net economic benefit to all those who produce, consume and transport electricity – without specifically considering how the proposed project will affect customers.

[3] Net customer benefits across the different studies are not directly comparable due to different price bases and different modelling period.

[4] FTI Consulting is an independent global business advisory firm.

[5] The Project Marinus PACR adopted the market-wide cost benefit assessment that is embodied in the RIT-T.

3. Background and key assumptions

Project Marinus is a staged 1500 MW high voltage direct current interconnector between Tasmania and Victoria, including supporting high voltage alternating current interconnector transmission developments in Tasmania. Our project assessments have consistently shown that a 1500 MW capacity interconnector, constructed in two 750 MW stages, maximises the potential value from the interconnector.

The complementary components of Project Marinus are the North West Transmission Developments (NWTD) in Tasmania, which are being progressed by TasNetworks. The NWTD include new and upgraded overhead transmission lines that will link Cressy, Burnie, Sheffield, Staverton, Hampshire, and East Cam. These new and upgraded transmission lines are required to support the interconnector capacity to be provided by Marinus Link.

Key modelling assumptions: FTI's report outlines the inputs, assumptions and scenarios that have been employed in the updated customer benefit analysis. Where possible, this information is consistent with data and assumptions set out in AEMO's 2023 Inputs, Assumptions and Scenarios Report (IASR)[6], largely in line with the 'Step Change' scenario. Where other data or assumptions have been adopted, the reason for using that information is explained in FTI's report.

Marinus Link timing: for the purposes of this modelling exercise, FTI assumes the first cable to be in operation by 2030, with the second cable assumed to be in operation from 2033. The timing for operation of the second stage is under review and continuing to be informed by AEMO's 2024 ISP and subsequent ISPs.

Competition benefits: to estimate wholesale prices, FTI uses a "Bertrand" pricing methodology, which assumes that generators have, over time, learned or understand their position in the merit order and increase their bid to just below that of the next generator in the merit order. This typically results in market prices that are higher than the short run marginal cost of production of the marginal generator and is more reflective of actual NEM spot market outcomes. FTI uses this approach as it has found that it reflects more accurately actual bidding behaviour of generators in the NEM.

Project Marinus dependent supply: FTI assumes that introducing Project Marinus will unlock a combination of upgrades to existing hydro capacity (390 MW), new pumped hydro (750 MW), and additional high capacity factor wind (600 MW). With two Marinus Link cables, FTI assumes that the Tasmanian Renewable Energy Target (TRET)[7] is met given the additional export capacity that Project Marinus provides.

Scenarios: FTI carried out its assessments across a range of demand scenarios given there is material uncertainty around projected electricity demand in Tasmania across AEMO's forecasting scenarios.

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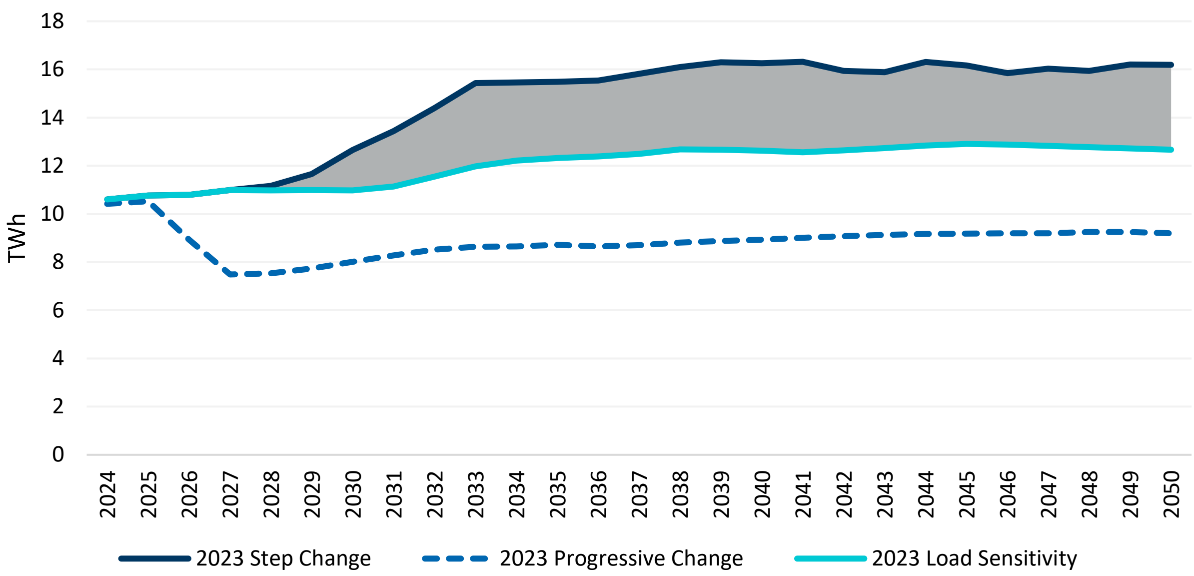
6 https://aemo.com.au/-/media/files/major-publications/isp/2023/2023-inputs-assumptions-and-scenarios-report.pdf?la=en

7 FTI assumes meeting TRET requires 21 TWh of renewable generation by 2040.

FTI modelled AEMO's 2023 Step Change scenario and a Load Sensitivity with reduced Tasmanian electricity demand (**Figure 1**).

Figure 1: FTI's assessment covers a range of demand outcomes to reflect uncertainty



4. Impact of Project Marinus on wholesale electricity prices

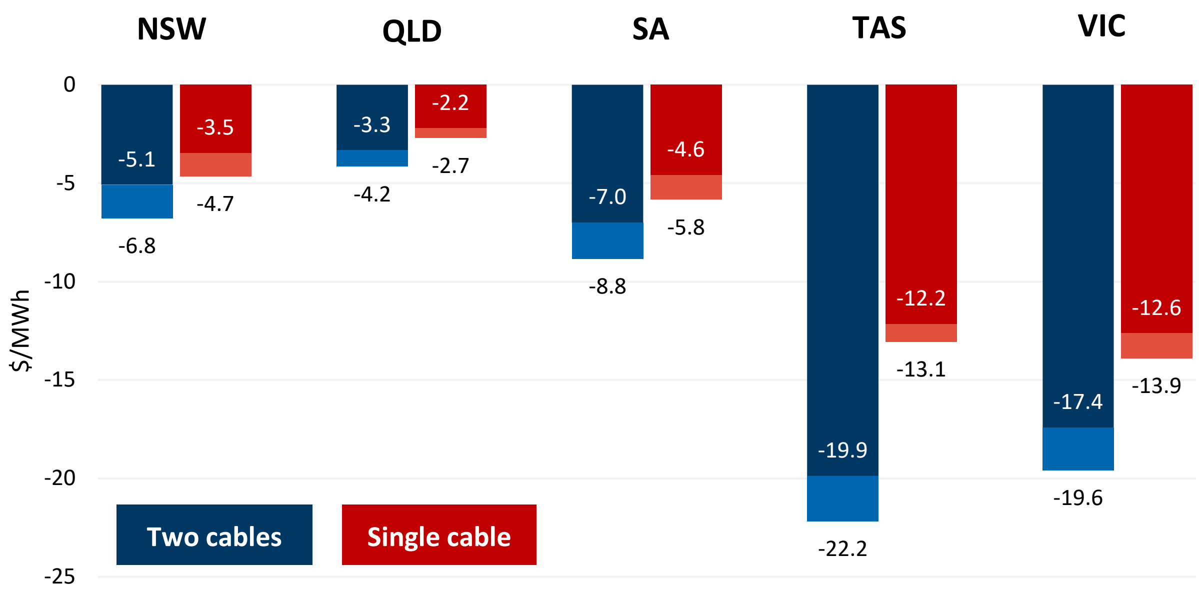
Electricity interconnectors are transmission assets that link two different price zones and allow for generation to be transferred from lower-priced regions to higher-priced regions. This benefits customers in the high price region, who now have access to cheaper sources of electricity, and it also benefits both connecting regions in the sense that customers now have access to additional sources of electricity, which increases the security of supply at both ends.

Consistent with FTI's previous customer benefits analysis, FTI's 2023 study shows that Project Marinus is expected to materially reduce wholesale prices in all NEM regions. The largest average annual wholesale price reductions during the 2031-50 study period occur in Tasmania ($20-22/MWh reduction[8]) and Victoria ($17-20/MWh reduction), with smaller price reductions forecast for other NEM regions (Figure 2). FTI also modelled wholesale price reductions under a one cable scenario, which reduced the expected wholesale price impact to $12-13/MWh in Tasmania and $13-14/MWh in Victoria.

The effect of the reduction in wholesale electricity prices is expected to equate to an annual $148 to $165 reduction in energy bills in Tasmania and $70 to $78 in Victoria compared to the Without Marinus counterfactual.

[8] Range is based on whether the Step Change scenario or Load Sensitivity is used.

Figure 2: Average reduction in wholesale prices, 2031-2050 (2023 dollars)[9]

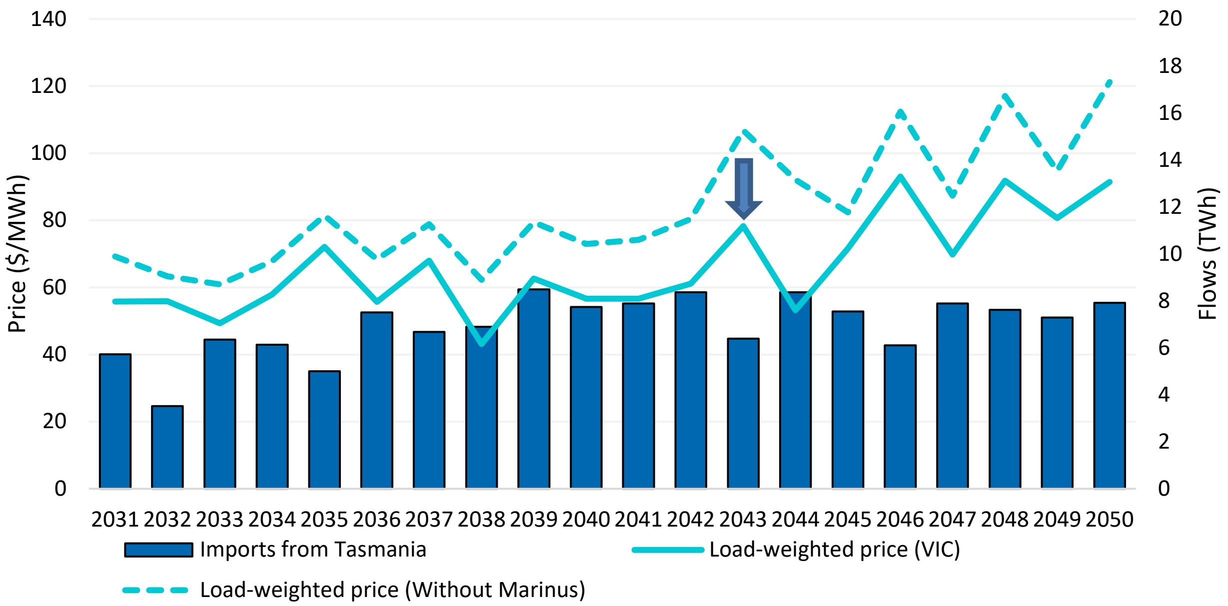


The decrease in wholesale prices in FTI's modelling is primarily driven by:

- **Unlocking large volumes of renewable generation in Tasmania.**
    - In the absence of Project Marinus, Basslink (the sole link between Tasmania and the mainland NEM), is frequently fully utilised. FTI's modelling indicates that Basslink's maximum capacity constrains exports from Tasmania in 83% of all periods modelled from 2031-2050, in the absence of Project Marinus.
    - Introducing Project Marinus reduces congestion between Tasmania and Victoria, which paired with Project Marinus-dependent capacity additions, allows for large volumes of low-cost Tasmanian generation to flow to the mainland (Figure 3). For example, FTI forecasts that in 2035 a two cable Marinus Link increases Tasmania to Victoria flows by 3.6 TWh.

[9] Light blue and light red shading represent the range of outcomes, based on whether the Step Change scenario or Load Sensitivity is used.

Figure 3 Prices and imports from Tasmania to Victoria, with Project Marinus



- **Allowing more displacement of thermal gas generation with lower cost renewables.**
  - In the Without Project Marinus counterfactual, gas generators are increasingly used to cover periods of low renewable generation, as coal-fired generators retire and NEM-wide demand increases.
  - Project Marinus has a material impact on NEM-wide gas generation, as the additional interconnection, combined with low-cost Tasmanian pumped hydro capacity and high-quality wind resource, enables renewable capacity in Tasmania to cover periods of low renewable generation and high demand on the mainland.
  - Tasmanian wind has a high capacity factor relative to mainland wind and solar[10], and also provides greater resource diversity to mainland wind farms[11]. This complementary profile increases the share of demand (including periods of high demand) that low-cost renewable generation can meet.
  - The marginal gas peaking plants on the mainland are significantly displaced as a result of Project Marinus, with annual gas generation reducing by between 2-5 TWh from 2033-2050 relative to the Without Project Marinus counterfactual (Figure 4).

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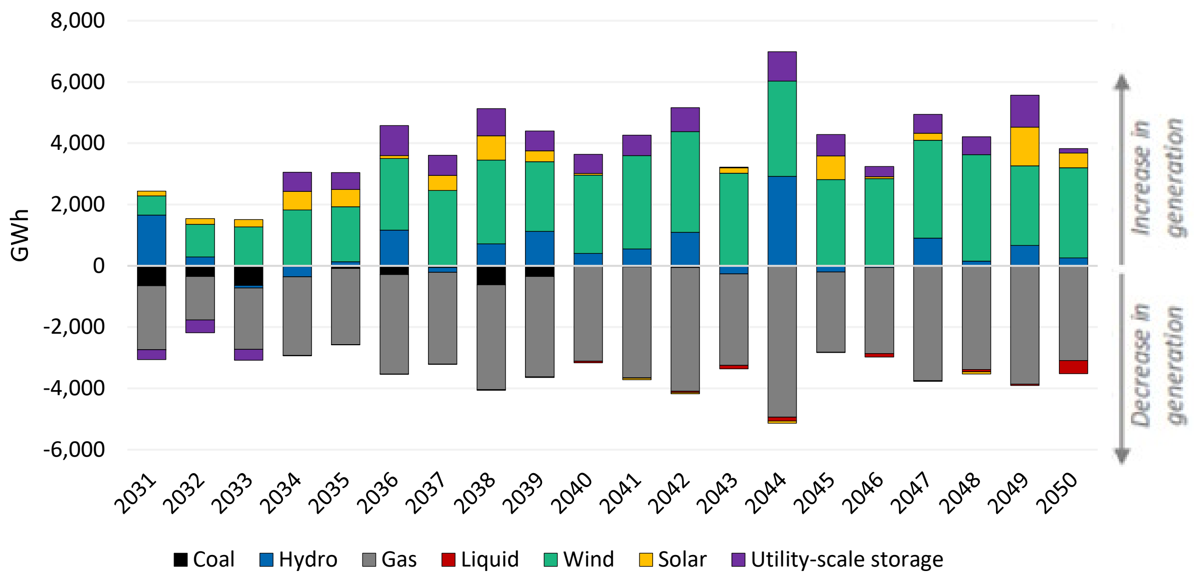
[10] See AEMO's 2023 Inputs, Assumptions and Scenarios Report workbook: https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios

[11] AEMO 2022 Integrated System Plan. https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/2022-integrated-system-plan-isp.pdf?la=en

Figure 4 Annual change in NEM generation resulting from Project Marinus



5. Customer benefit of Project Marinus

Despite significant changes in market dynamics and outlook since the 2020 study, as well as increased Project Marinus costs, FTI's updated analysis indicates that customers could still expect to benefit materially from Project Marinus.

As outlined above in Section 4, Project Marinus provides material downward pressure on wholesale prices due the additional Tasmanian generation it unlocks, coupled with the benefit of displacing higher-priced generation (largely gas-fired generation and demand response). These reductions in wholesale electricity prices equate to a total gross NEM customer benefit from Project Marinus of $14.8-16.9 billion[12] over the modelling period (excluding the impact of higher network costs). In the one link scenario, the gross customer benefit is $10.4-11.8 billion.

After project costs[13] and interconnector residues are accounted for, FTI forecasts net customer benefits of $10-12.5 billion for two cables and $7.6-9.4 billion for one cable (Figure 5). This suggests that around 75% of the net customer benefits that could be realised from building two Marinus Link cables could be realised by constructing only one Marinus Link cable.

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[12] Range is based on whether the Step Change scenario or Load Sensitivity is used.

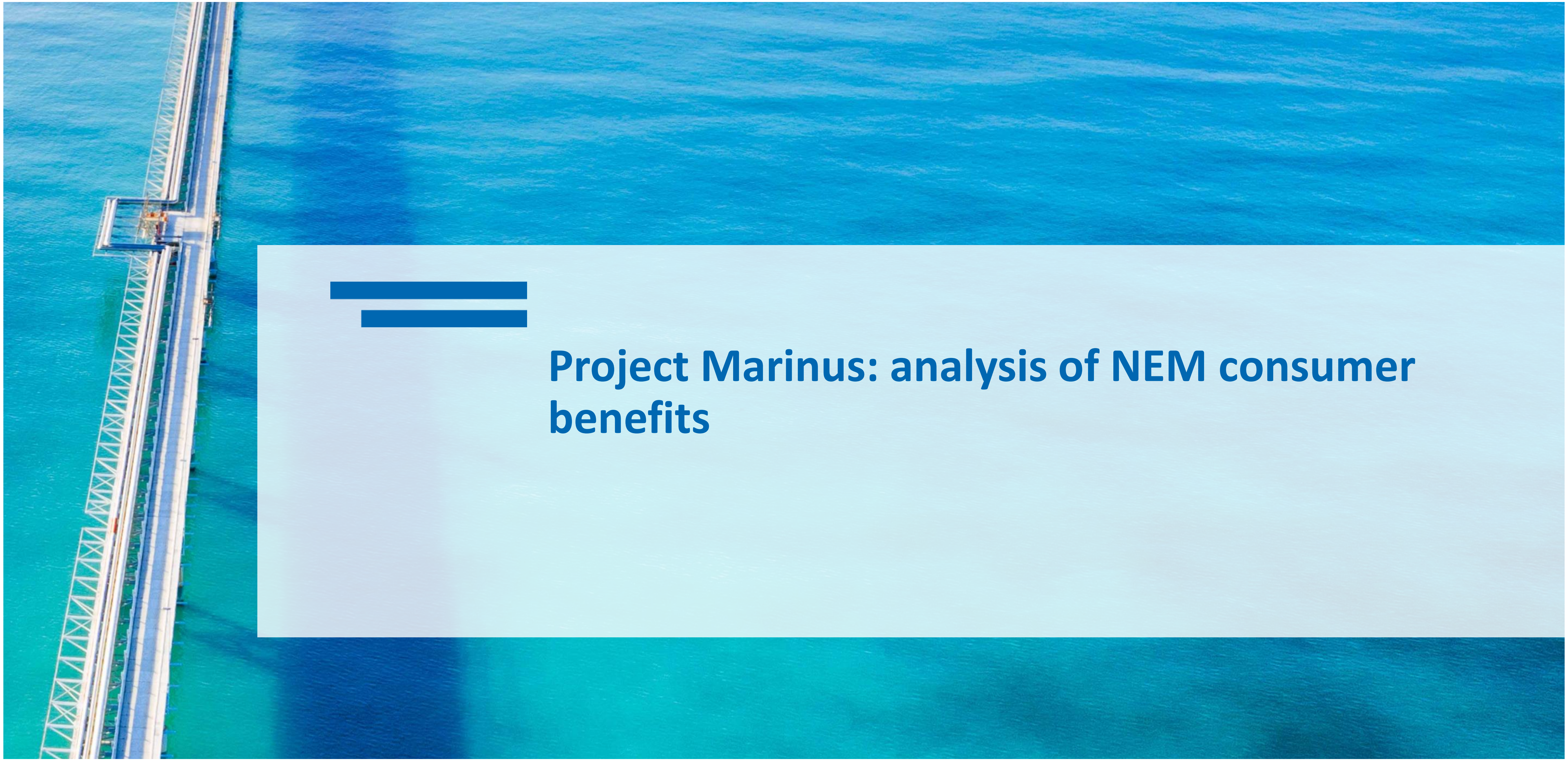
[13] FTI use a single discount rate of 7.0% (real, consistent with AEMO's 2023 IASR Central) to calculate the present value of costs and benefits. Project Marinus costs includes forecast annuitised capex and annual opex across our modelling period (2031 to 2050) for both Marinus Link and NWTD Project.

FTI also notes that net customer benefits associated with Project Marinus in this 2023 study are higher than net customer benefits of $5.4 billion in their 2020 work[14]. They highlight the following factors as contributing to this outcome:

- Faster exit of coal-fired generation and faster uptake of renewable capacity increases the firming value provided by Tasmanian hydro and pumped hydro resources.
- Gas and coal prices have increased, reflecting changing market conditions and inflation.
- Small increase in assumed capacity factors for Tasmanian wind generation relative to the 2020 ISP.

Figure 5 Net customer impact of Project Marinus, $bn, Present Value 2031-2050 (2023 dollars)

14 Net customer benefits across the different studies are not directly comparable due to different price bases and different modelling period.



Project Marinus: analysis of NEM consumer benefits

FTI CONSULTING

December 2023

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Contents

Executive Summary

Background and key findings

Background and Context

- Marinus Link ("Project Marinus") is a proposed interconnector between Tasmania and Victoria being developed by Marinus Link, a subsidiary of TasNetworks.
- It is proposed to be composed of either one or two High Voltage Direct Current ("HVDC") links with capacities of 750 MW each. For the purposes of modelling, the first stage is targeted to be in operation in calendar year 2030 with the second stage assumed to be in operation by the end of calendar year 2032. The timing for operation of the second stage is under review and continuing to be informed by AEMO's 2024 ISP and subsequent ISPs.
- It would be the second interconnector (after Basslink, a 478 MW HVDC link) developed between Tasmania and Victoria.
- It is expected that in parallel with the introduction of Project Marinus, Tasmania would develop a combination of dispatchable and variable renewable energy ("VRE") generation capacity. Notably, this includes the development of new pumped hydro storage and upgrades to existing hydro capacity (together known as the 'Battery of the Nation') and high capacity factor wind.
- FTI Consulting ("FTI") has been engaged by Marinus Link to assess the benefits of Project Marinus for consumers in Australia's National Electricity Market ("NEM") as a result of expected changes in wholesale electricity prices and interconnector residues, relative to the costs of the project.
- This report presents our findings and is an update to our work for TasNetworks in 2020, which also assessed the benefits of Project Marinus to consumers in the NEM.[1]
- AEMO's 2022 Integrated System Plan ("ISP") found that Project Marinus is expected to provide a market benefit of $4.6bn in net present value terms.[2]

Key findings

Project Marinus is expected to generate $10.4bn to $16.9bn of consumer benefits from lower wholesale electricity prices across the NEM, significantly exceeding the costs of construction[3]

- From 2031 to 2050, Project Marinus and the additional Tasmanian generation capacity it facilitates are expected to deliver **$14.8bn to $16.9bn** in consumer benefits (for two Marinus Link cables) across the NEM in net present value terms, before taking into account the costs of construction and operation and changes in interconnector residues.[4] For one Marinus Link cable, consumer benefits are estimated to be **$10.4bn to $11.8bn**.
- The expected reduction in wholesale prices is driven by **increased access to high-quality wind resources in Tasmania,** as well as to the existing Tasmanian hydroelectric fleet and high-quality new entrant pumped hydro energy storage**.** The electricity generated by this capacity is expected to be exported to the NEM, leading to **reduced dispatch of gas generation and demand response and, consequently, lower wholesale electricity prices.**
- This compares to the expected costs of Project Marinus across the same period of **$2.1bn** for one cable **and $3.2bn** for two cables, including associated costs of the North-West Transmission Developments ("NWTD") Project.[5]

These benefits arise from expected reductions in wholesale electricity prices that consumers across the states in NEM should see in their energy bills

- For two cables, average wholesale electricity prices are estimated to fall by **$20 to $22 per MWh for Tasmania** and **$17 to $20 per MWh for Victoria.** For one cable, the fall in electricity prices is expected to be **$12 to $13 per MWh for Tasmania** and **$13 to $14 per MWh in Victoria.**
- The effect of the reduction in wholesale electricity prices is expected to equate to an annual **$148 to $165** reduction in energy bills in Tasmania for two cables. This falls to **$90 to $97** for one cable.
- For Victorian consumers, this is expected to be **$70 to $78** for two cables and **$51 to $56** for one cable.
- Reductions in consumer energy bills due to lower wholesale electricity prices are expected across all states in the NEM ranging from **$15 to $35** for two cables and **$10 to $23 per household** for one cable.

Our assessment indicates Project Marinus can be expected to generate net benefits of $7.6bn to $12.5bn for consumers in the NEM

- We estimate the **net impact** on consumers across the NEM by also taking into account the impact on interconnector residues[6] and costs of Project Marinus in net present value terms.
- We estimate the net benefits to be **$10.0bn to $12.5bn** for two cables and **$7.6bn to $9.4bn** for one cable.

(1) FTI Consulting, *Assessing the benefits of Project Marinus – Final Report, August 2020.* (2) AEMO, *2022 Integrated System Plan – Appendix 6. Cost Benefit Analysis* (link), pages 43 & 44. Figure reported applies to "Step Change" scenario. (3) Range reflects our assessment across different scenarios. (4) See page 15 for an explanation of interconnector residues. (5) NWTD is being undertaken by TasNetworks to upgrade transmission network infrastructure in Tasmania (link). See page 15 for more details on Project Marinus costs. (6) Average load-weighted prices across modelled period of 2031-50.

Background and Context

Background and context

About Marinus Link

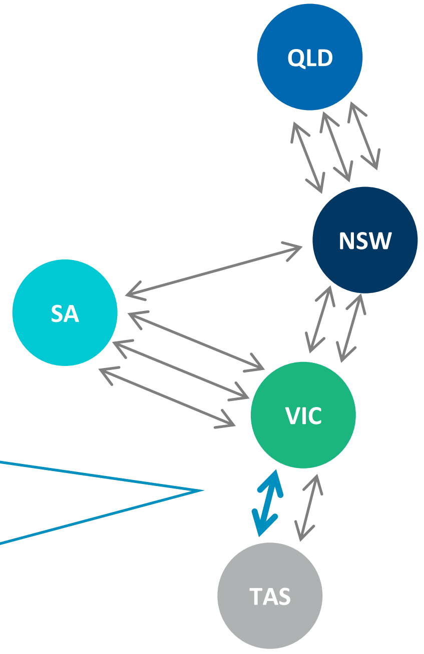
- Marinus Link (“Project Marinus”) is a proposed 1,500 MW High Voltage Direct Current (“HVDC”) interconnector between Tasmania and Victoria being developed by Marinus Link, composed of two cables of 750 MW each. It would be the second interconnector (after Basslink, a 478 MW HVDC link) developed between Tasmania and Victoria.
- The Australian Energy Market Operator’s (“AEMO”) 2022 Integrated System Plan (“ISP”) found that Project Marinus is expected to provide a market benefit of $4.6bn net present value terms.[1]
- For the purposes of modelling, the first stage is targeted to be in operation in calendar year 2030 with the second stage assumed to be in operation by the end of calendar year 2032. The timing for operation of the second stage is under review and continuing to be informed by AEMO’s 2024 ISP and subsequent ISPs.
- AEMO expects that Project Marinus will provide greater access to Tasmania’s dispatchable and variable renewable energy (“VRE”) generation capacity, providing resource diversity and reducing the need for additional capacity on the mainland.[2] Specifically, this includes the development of new pumped hydro storage and upgrades to existing hydro capacity (together known as the ‘Battery of the Nation’) and high capacity factor wind.[3]

Project Marinus

A proposed **1,500 MW HVDC interconnector.**

The **second interconnector between Tasmania and Victoria**.

Modelled **delivery dates of July 2030** and **January 2033** for link 1 and link 2 (each 750 MW) respectively.



Context of this report

- FTI Consulting (“FTI”) has been engaged by Marinus Link to produce an updated assessment of the benefits of Project Marinus to consumers in the NEM.
- Since FTI’s work in 2020, changes have occurred in the NEM which have highlighted the need to refresh the analysis of the benefits of Project Marinus on NEM consumers, including:
  - AEMO updated its NEM Optimal Development Path in its 2022 ISP, in which Project Marinus was made an actionable project.
  - Australian governments have introduced tighter emissions targets and coal is being retired faster than previously expected.
  - Multiple emissions policy positions have been updated, including the national 2030 emissions target, the recently announced expanded Capacity Investment Scheme and VRET.[4]
  - AEMO has updated its forecast NEM emission trajectories, which are modelled as carbon budgets.[5]
  - The estimated cost of the Marinus cables have been updated.[6]
  - Updates to the Renewable Energy Zones (“REZs”), including a new candidate offshore REZ in North-East Tasmania, and updates to the resource limits (MW) of each offshore REZ in the NEM.[7]
  - Forecasts for higher electricity consumption in Tasmania in the short to medium-term, largely due to the anticipated growth of the hydrogen production industry.[8]
- In this report, we therefore update our 2020 analysis to take account of the latest forecasts and information contained within AEMO’s 2023 Inputs, Assumptions and Scenarios Report (“IASR”) and Electricity Statement of Opportunities (“ESOO”).
- The report is intended to complement existing analysis on Project Marinus, such as FTI’s work in 2020, and any existing or updated RIT-T analysis. It presents a consumer-focused welfare analysis, focusing on the benefits of Project Marinus in terms of its impact on wholesale electricity prices across the NEM.

(1) AEMO, *2022 Integrated System Plan – Appendix 6. Cost Benefit Analysis* (link), pages 43 & 44. (2) AEMO, *2022 Integrated System Plan*, June 2022 (link), page 73. (3) For example, AEMO identify wind opportunities of in 1.1 GW (Central Highlands) and 1.3 GW (North West). AEMO, *2022 Integrated System Plan*, June 2022 (link), page 43. (4) AEMO, *2023 Inputs Assumptions and Scenarios Report*, July 2023 (link), page 26. (5) AEMO, *2023 Inputs Assumptions and Scenarios Report*, July 2023 (link), page 46. (6) Source: Marinus Link (7). AEMO, *2023 Inputs Assumptions and Scenarios Report*, July 2023 (link), pages 128-133 (8) AEMO, *2023 Electricity Statement of Opportunities*, August 2023 (link), page 146.

The NEM is undergoing a rapid transition away from thermal generation capacity towards renewable power sources including wind and solar

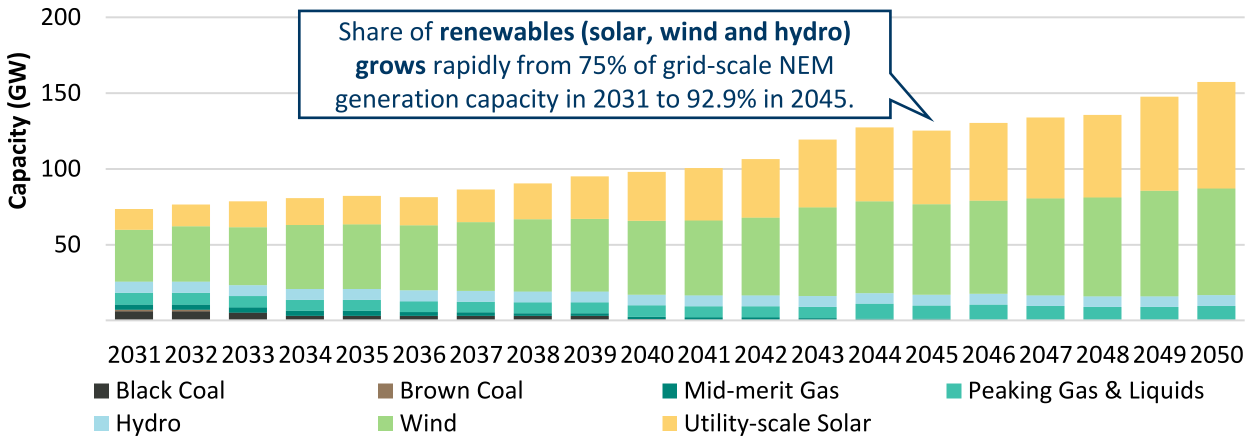
NEM is transitioning rapidly to renewables and since 2020, the move away from coal has accelerated

- The **NEM is currently undergoing a period of rapid transition**, driven by government policy and net zero ambitions. Examples of such policies include:
  - Tasmanian Renewable Energy Target ("TRET"): Increase Tasmania's renewable energy output by 200% based on 2022's renewable energy figures.[1]
  - Victorian Renewable Energy Target ("VRET"): The Victorian Government has announced an intention to legislate updated targets for the proportion of electricity generated by renewable energy to 65% by 2030 and 95% by 2035.[2]
  - Capacity Investment Scheme ("CIS"): The Federal Government has developed a national framework to target 9 GW of clean dispatch capacity and 23 GW of variable capacity nationally.[3]
- Both the way electricity is generated and how it is consumed is evolving:
  - **Generation is shifting away from thermal generation, most notably coal, towards renewables** sources such as wind, solar and hydro.
  - **Coal generation capacity is expected to be rapidly** phased out. AEMO expects that by 2031, 67% of the NEM's total coal capacity in 2023[4] will be retired.
  - Meanwhile, AEMO also expects **wind and solar generation capacity to grow** from 20 GW in 2023, to 84 GW by 2040 and 139 GW by 2050.[5]
  - **Net demand for electricity from the grid is also developing**, as technologies including residential solar, batteries, and electric vehicles grow in prevalence and impact the flexibility and profile of consumers' net demand.
- AEMO notes that Project Marinus is considered "nationally strategic" and listed Project Marinus as an **actionable project** in the 2022 ISP.[6]

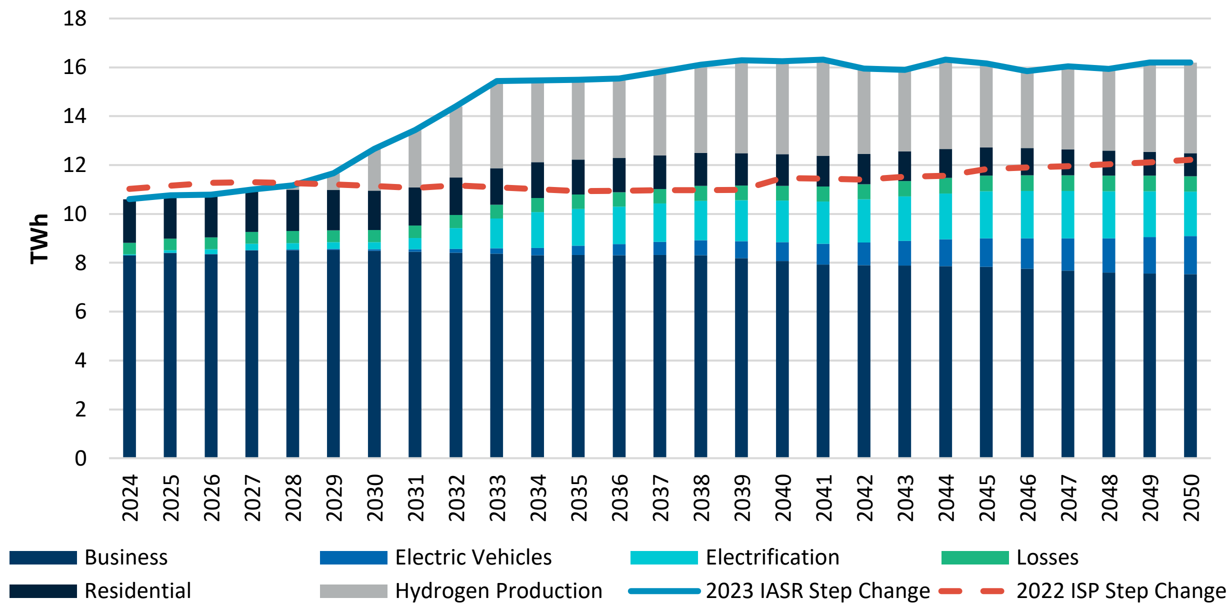
Within Tasmania, expectations for hydrogen consumption has increased significantly in recent years

- The Step Change scenario set out in AEMO's 2023 IASR forecasts incorporates significantly higher annual electricity consumption compared to the Step Change scenario in the 2022 ISP.[7]
  - By 2033, there is forecast to be more than **4.3 TWh** of additional consumption in the 2023 IASR compared to the 2022 ISP. In 2050, this difference is forecast to still be nearly **4 TWh** in 2050.
  - This difference is driven mainly by an increase in consumption due to hydrogen production, with the 2023 IASR forecasting around **3.5 TWh** per annum of such consumption from 2033 to 2050.
- The forecast increase in demand in Tasmania represents a significant increase over 2022 ISP, where hydrogen consumption in Tasmania was estimated to be 1.5 TWh by 2050.

NEM Installed Capacity, 2022 ISP Step change scenario[8,9]



Tasmania Electricity Consumption, 2023 IASR Step change scenario[10]



(1) Department of State Growth, Tasmanian Government, *Tasmanian Renewable Energy Action Plan,* December 2020 (link) (2) Department of Energy, Environment and Climate Action, *Victorian renewable energy and storage targets*, February 2023 (link) (3) Department of Climate Change, Energy, the Environment and Water, *Capacity Investment Scheme* (link) (4) AEMO, *2022 Integrated System Plan*, June 2022 (link) (5) AEMO, *2022 Integrated System Plan*, June 2022 (link) (6) AEMO, *2022 Integrated System Plan*, June 2022 (link), pages 13, 29. (7) AEMO, *2023 IASR Assumptions Workbook*, August 2023 (link) (8) AEMO, *2022 Integrated System Plan*, June 2022 (link) (9) Throughout the report, all dates in charts show financial year ending unless otherwise stated (10) AEMO, *National Electricity & Gas Forecasting*, August 2023 (link).

Modelling approach

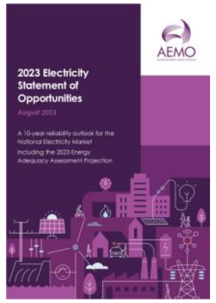
Our approach to assessing the benefits of Project Marinus consists of forecasting and comparing wholesale electricity prices with and without the Marinus cables in the NEM's electricity network

Inputs

IASR (2023)
(generation supply, planned retirements, policy constraints, build costs, gas prices), using the Step Change scenario, to resemble the unreleased AEMO ISP 2024 model.

Updated with AEMO's latest view
(demand)

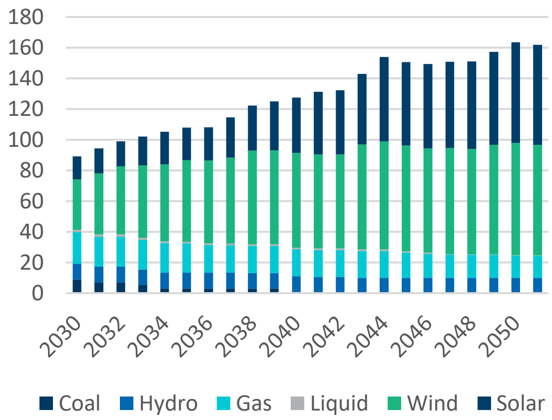
Combination of the 2023 IASR and ESOO (Aug 2023), reflecting AEMO's most up-to-date latest views[1]



Capacity Mix

Using our in-house power market model, calibrated using the 2023 IASR, **we estimate the baseline capacity mix for each region** needed to meet capacity requirements while minimising costs.

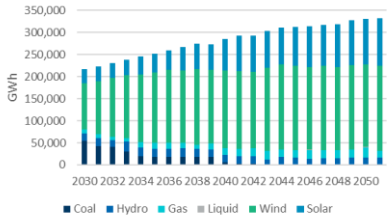
NEM Installed Capacity (GW)



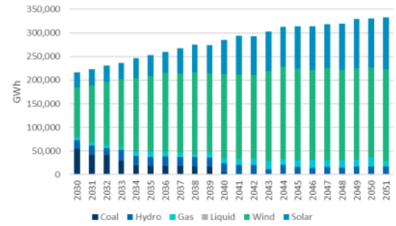
Dispatch and wholesale electricity prices

Our model determines generation profile and prices on an hourly basis **using the baseline capacity mix as a starting point.[2]**

NEM Total Generation (GWh)



Without Project Marinus



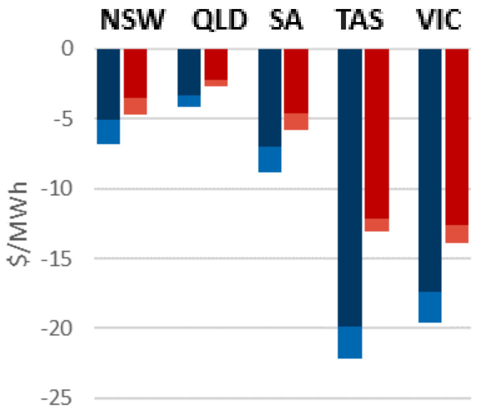
With Project Marinus

Price output

Impact on wholesale electricity prices equals **the difference between the prices observed** in a version of our model without Project Marinus…

…and a version with **either one or two Marinus cables** present in the NEM.

Average reduction in wholesale electricity prices

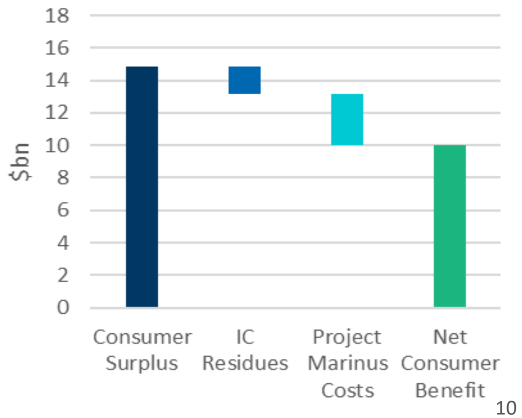


Benefits calculation

Overall consumer benefit assessed based on modelled change in prices and expected consumption profiles

…and combined with changes in network costs[3] and Project Marinus' own costs

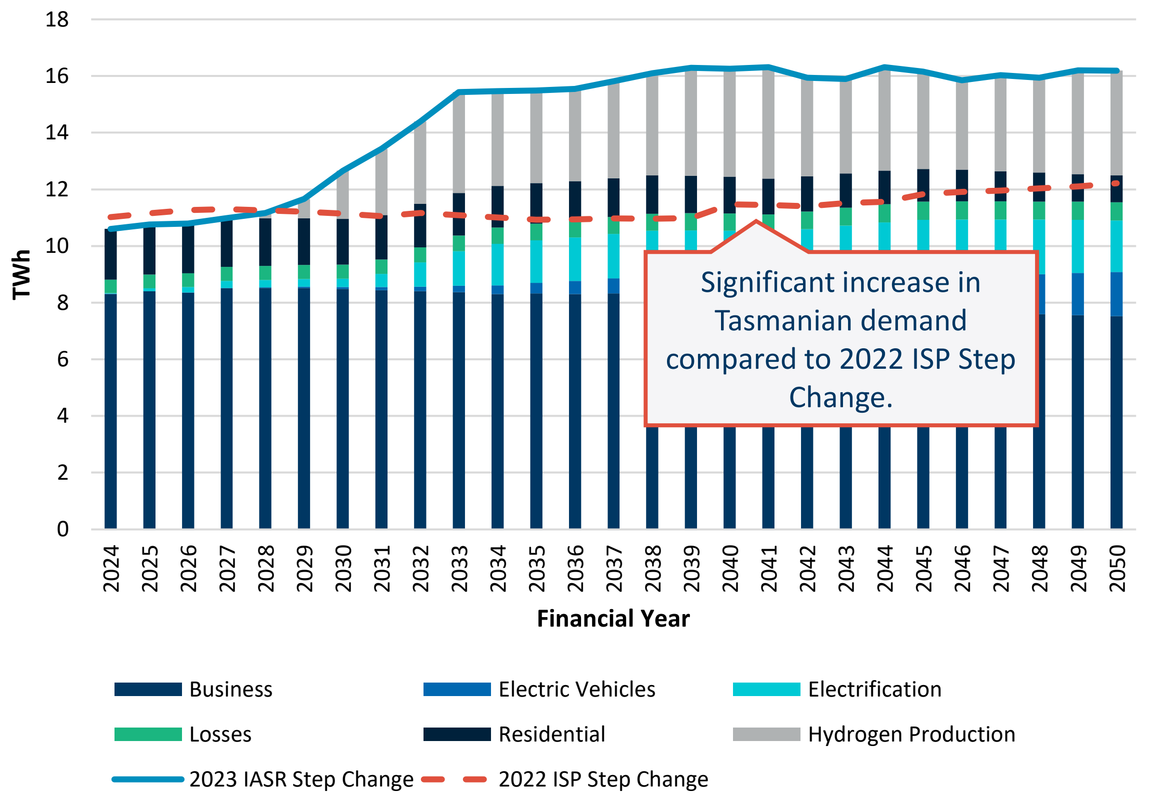
Consumer benefits calculation



(1) Draft 2024 ISP expected to published in December 2023, following the completion of these works. (2) See page 12 for more details. (3) We assume that any incremental changes in the rents earned by other interconnectors are passed through to consumer bills through network charges.

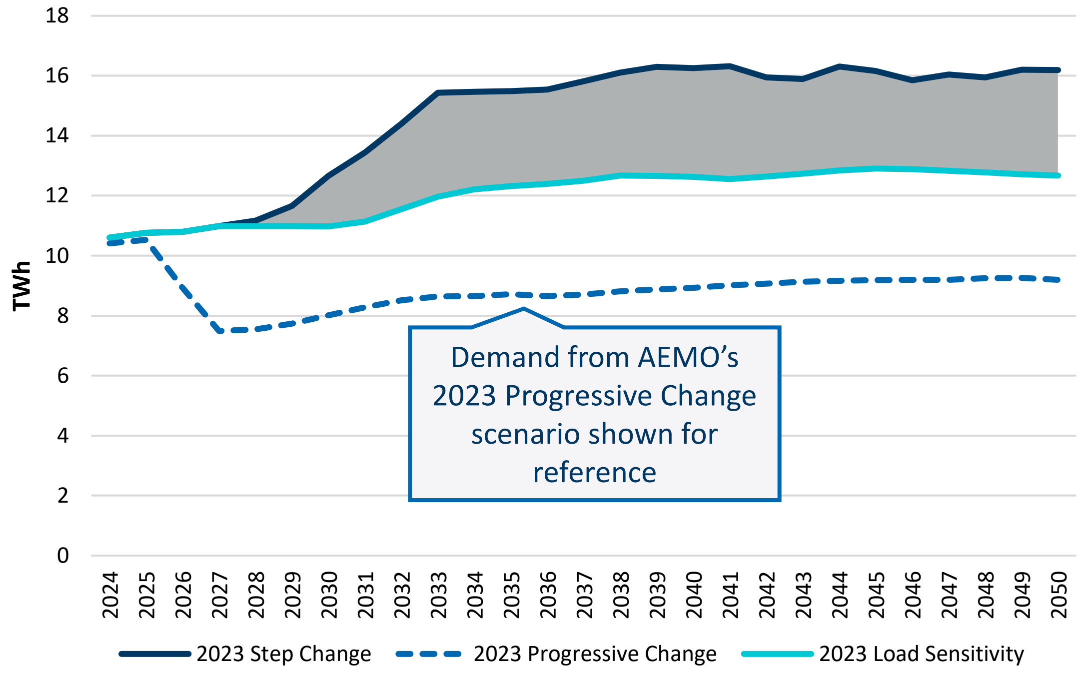
We have carried out our assessment across a range of demand outcomes given there is now material uncertainty around projected electricity demand in Tasmania across AEMO's forecasting scenarios

Expected Tasmanian Electricity Demand has increased substantially since 2022 ISP



- Compared to the 2022 ISP 'Step Change' scenario, AEMO's IASR 2023 'Step Change' scenario assumes a materially higher Tasmania electricity demand in 2050, increasing from c. 12 TWh in 2022 ISP to 16 TWh in 2023 IASR.
- A significant factor in this increase in demand can be attributed to **growth in demand for hydrogen production** expected under the 2023 IASR 'Step Change' scenario.

Our assessment covers a range of demand outcomes to reflect uncertainty



- AEMO's **2023 IASR reflects greater uncertainty in Tasmania electricity demand** going forward, with the 2023 IASR 'Progressive Change' scenario expecting less than 10 TWh of Tasmanian demand by 2050.
- As such, we have estimated price impacts and net benefits across a range of potential demand outcomes to account for uncertainty in AEMO's demand forecasts. We model AEMO's 2023 'Step Change' scenario and a 'Load Sensitivity' with reduced Tasmanian electricity demand.

We estimate a baseline capacity mix in line with AEMO's 2023 IASR Step Change scenario, adjusted for the absence of Project Marinus

Baseline NEM generation mix

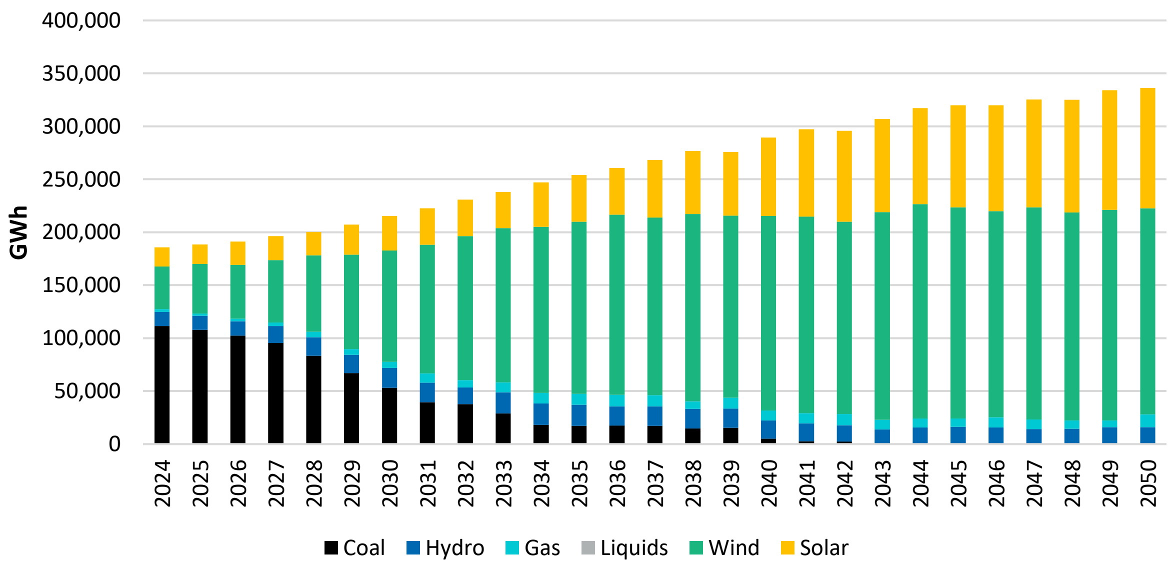
We establish a **baseline generation mix** (see graph below), that reflects the generation profile that we expect to be present in the NEM **in the absence of Project Marinus**.

To determine this baseline, we calibrate our in-house power market model of the NEM with AEMO's 2023 IASR assumptions (Step Change Scenario), assuming that:

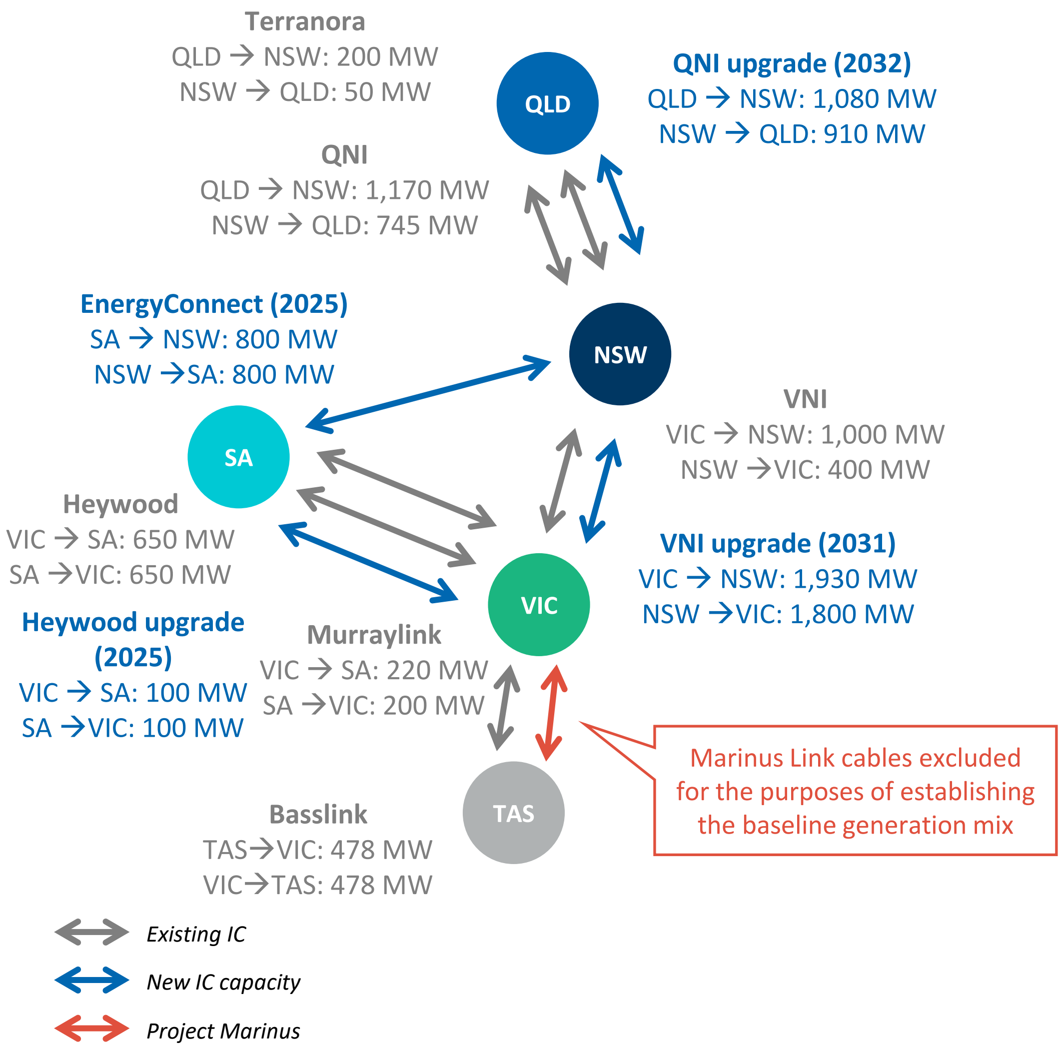
- price regions are connected according to the current and planned system of interconnectors (as shown on the right);
- this topology reflects all committed and anticipated transmission projects in the 2023 IASR, **but with Project Marinus excluded;**
- updating for the 2023 IASR to **also exclude planned Project Marinus-dependent generation investments** (see next page for more detail); and
- coal-fired generators are retired in line with AEMO's latest assumptions.

Removal of Project Marinus results in some key differences with the 2023 IASR Step Change Scenario in our Without Project Marinus counterfactual:

- **In Tasmania:** Less build-out **and** more curtailment of Tasmanian wind.
- **In Victoria:** More reliance on gas generation and imports from other states to serve demand.



Assumed NEM topology[1, 2]



(1) AEMO, *2023 Inputs Assumptions and Scenarios Report*, July 2023 (link), pages 140-148 (2) Figures displayed for IC capacity are for Winter Reference.

We add Project Marinus-dependent capacity to Tasmania in our modelling runs with Project Marinus in operation in order to assess the impact of the renewables that Project Marinus is expected to support

Tasmania Hydro Upgrades

Total Hydro capacity = 390 MW

West Coast (100 MW)
Tarraleah (150 MW)
Gordon (90 MW)
Non-scheduled (50 MW)

- According to AEMO, Project Marinus is expected to unlock investments to redevelop or upgrade capacity of existing Hydro assets in Tasmania.[1]
- These investments are expected to result in a total of **390 MW** of additional Tasmanian Hydro capacity.
- We assume that these Hydro upgrades are made with **either one or two** Marinus Links operational.

Two Marinus Link Cables

Hydro upgrades (390 MW)
Wind (600 MW)
Pumped Hydro (750 MW)

- With two Marinus Link cables, we assume that TRET is met given the additional export capacity that Project Marinus provides.
- For the purposes of our modelling, we assume that this means generation of **21 TWh** of renewable generation by **2040.**[2]
- We estimate that meeting the TRET requires 600 MW of additional wind capacity to be built in Tasmania by 2040.[3]

One Marinus Link Cable

Hydro upgrades (390 MW)
Wind (300 MW)

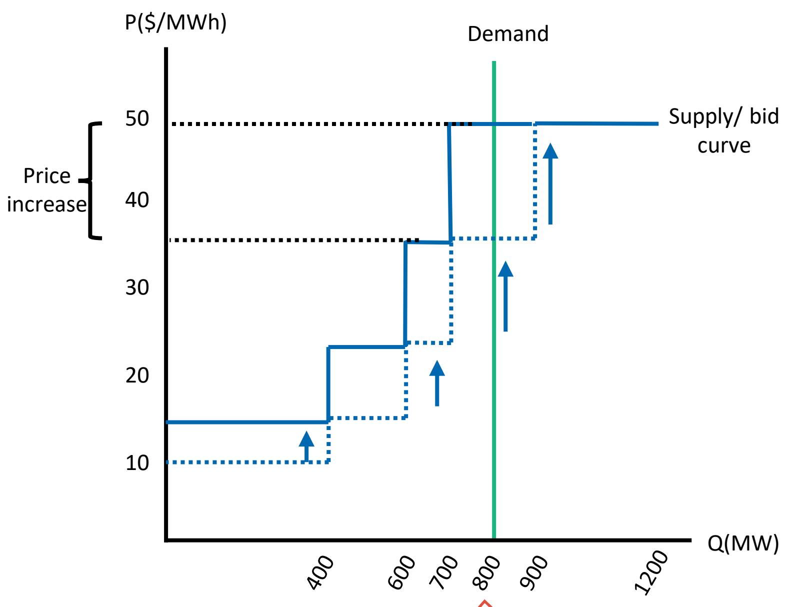
- With only one Marinus Link cable, we assume that Tasmanian wind capacity build is 300 MW – half of the capacity built with two cables.
- In addition, we assume that 750 MW of pumped hydro storage under the Battery of the Nation project is not constructed due to the reduced export capacity provided by Project Marinus compared to with two Marinus Link cables.

(1) See 2023 IASR Workbook, notes on Flow Path Augmentation Options sheet: *"With the introduction of Marinus link, the capacities of the following generators increase by: 100 MW across the west coast, 150 MW for Tarraleah and 90 MW capacity for Gordon."* (2) Including both grid-scale and rooftop PV - see 2023 IASR Workbook, Energy Policy Targets sheet. (3) Relative to AEMO's 2022 ISP Step Change 'counterfactual'. For more information see AEMO, *2022 Integrated System Plan*, June 2022 (link) – *Part C*.

We use Bertrand pricing and other simplifying assumptions to compute prevailing wholesale electricity prices

Generator bidding behaviour

- For the purposes of our modelling, we assume Bertrand pricing as an approximation for generating bidding behaviour, in line with our previous analyses.
- Bertrand pricing assumes that, over time, all generators have developed an understanding of their position of the merit order, and therefore increase their bid to marginally below the marginal cost of the next cheapest generator (rather than bidding at their own marginal cost, as is often assumed).
- Bertrand pricing therefore ensures that the dispatch respects the merit order of generator costs (thereby minimising system costs), while introducing an element of rational profit maximising behaviour from market participants.
- An alternative assumption could be that generators bid according to some measure of their own costs, such as Short Run Marginal Cost ("SRMC"), Long Run Marginal Cost ("LRMC") or other variants.
- Previous FTI analysis has indicated that, while no one assumption fully captures the bidding behaviour of market participants, Bertrand pricing resulted in a closer approximation of historical prices compared to SRMC or LRMC-based approaches.
- In the last years of the modelling period, we revert to SRMC-based bidding behaviour to avoid unrealistic Bertrand-based bidding outcomes that result from the system being almost exclusively VRE generation, hydro and storage and the aggregated treatment of new entrant generation units within the model.



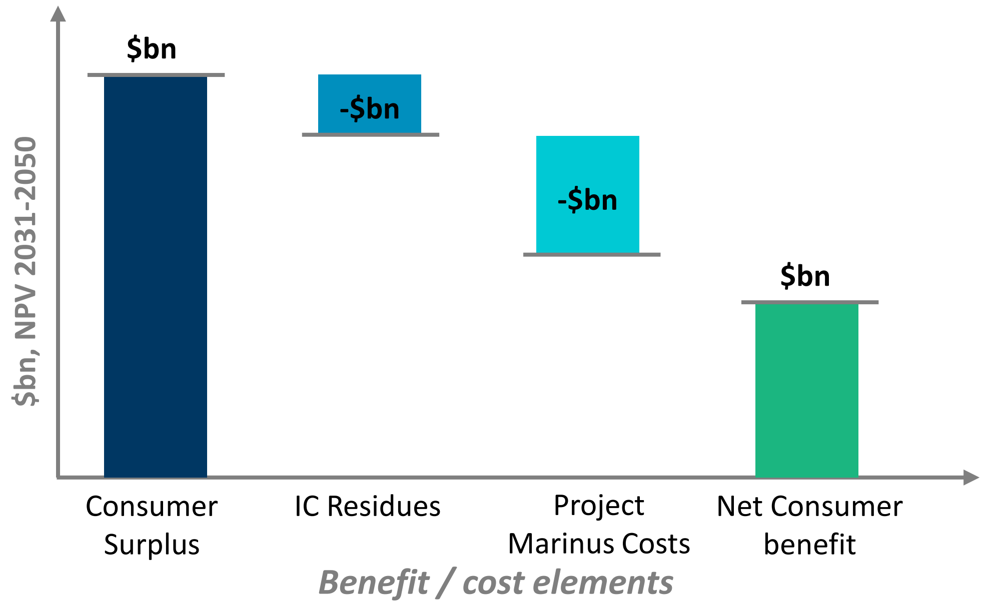
In this stylised example, Bertrand pricing results in the marginal generator bidding at $49.99/MWh (rather than $35/MWh). This means that 800 MW is now filled at $49.99 rather than at $35.

Tasmanian Pricing: Regulatory Instrument

- The prices that consumers pay for electricity in Tasmania are governed by long-term contractual arrangements between retailers and Hydro Tasmania. The methodology for calculating prices is derived from a 'rules-based' methodology outlined in the Wholesale Contract Regulatory Instrument.
- As a result of these arrangements, the price that consumers in Tasmania pay for electricity (the 'Tasmania contract price') would not be accurately reflected by the Tasmania spot price calculated in our power market model (either with or without the assumptions set out to the left).
- Instead, we make a simplifying assumption to estimate the Tasmania contract price:
  - We assume that the Tasmania contract price is equal to the Vic spot price as calculated in our power market model.
  - This is in line with the assumption made in our 2020 modelling, where, based on discussions with both Hydro Tasmania and the Tasmanian Government, it was agreed that the Victoria spot price would be a useful proxy for the Tasmania contract price. We have assumed that this assumption is still reasonable up to 2050.
  - No further adjustments are applied to account for other relevant elements of the Regulatory Instrument that may affect prices. Analysis of data from our 2020 work confirmed that the impact of such adjustments are likely to be immaterial or non-systematic in nature.

In line with the methodology used in our previous reports, our assessment of the net benefits of Project Marinus uses a consumer-focused approach

Cost-benefit analysis: illustration of the methodology



A pure economic approach calls for **total welfare analysis**…
…however, in this analysis we have only considered a more **consumer-focused welfare analysis**.

Specifically, we find the **Net Consumer benefit** of Project Marinus, which (unlike the **Net Societal benefit**) does not consider the impact on producer surplus arising from changes in wholesale electricity prices.

The change in consumer surplus considers the quantum of benefit accruing to consumers from lower wholesale electricity prices. This is then netted off against the change in interconnector residues ("IC residues")[1] and Project Marinus costs, which we assume Transmission Network Service Providers ("TNSPs") pass on to consumers through network charges.

- Our assessment of net consumer benefits follows the same framework as our 2020 report. Where appropriate, we have updated parameters and assumptions to be in-line with AEMO's latest methodologies or to align with changes in the NEM.
- We model the period **2031 to 2050** for each region and NEM-wide.
- We use a single discount rate of **7.0%** (real, consistent with AEMO's 2023 IASR Central assumption)[2] to calculate the present value of costs and benefits.
- IC residues represent the net impact on residues earned by interconnectors. We assume that these residues are allocated to different states on the basis of interconnector flows.[3] They are included because the introduction of Project Marinus is expected to change wholesale prices and flows between each region which in turn impact the amount of interconnector costs that are recovered from consumers. A single interconnector loss factor of **2.18%** is used to calculate IC rents across all lines.[4]
- Project Marinus costs includes forecast annuitised capex and annual opex across our modelling period (2031 to 2050) for both Marinus Link and NWTD Project.
  - For Marinus Link, forecast capex costs and annual opex costs are based on indicative cost estimates provided by TasNetworks, assuming a 40-year project life.
  - Costs for NWTD are forecast capex costs based on indicative cost estimates provided by TasNetworks.
- Costs and benefits incurred after 2050 are excluded from the analysis.[5]

(1) IC residues refers to the rents earned by interconnectors across the NEM transmission network, which are returned to consumers. (2) AEMO, *2023 IASR Assumptions Workbook*, August 2023 (link). (3) In line with methodology set out by AEMO for the Settlements Residue Auctions (link). (4) In our 2020 report, our calculation of IC residues excluded Basslink, which was treated as an unregulated interconnector that did not pass residues back to consumers. We assume that Basslink operates as a regulated interconnector over the modelling period and so we now include it within the calculation of IC Residues. (5) In our analysis, we assume that the costs of the additional Tasmanian generation and pumped hydro capacity facilitated by Project Marinus would be recovered through wholesale prices without any need for further subsidies or other funding mechanisms to be implemented.

Results – Pricing outcomes and cost benefit analysis

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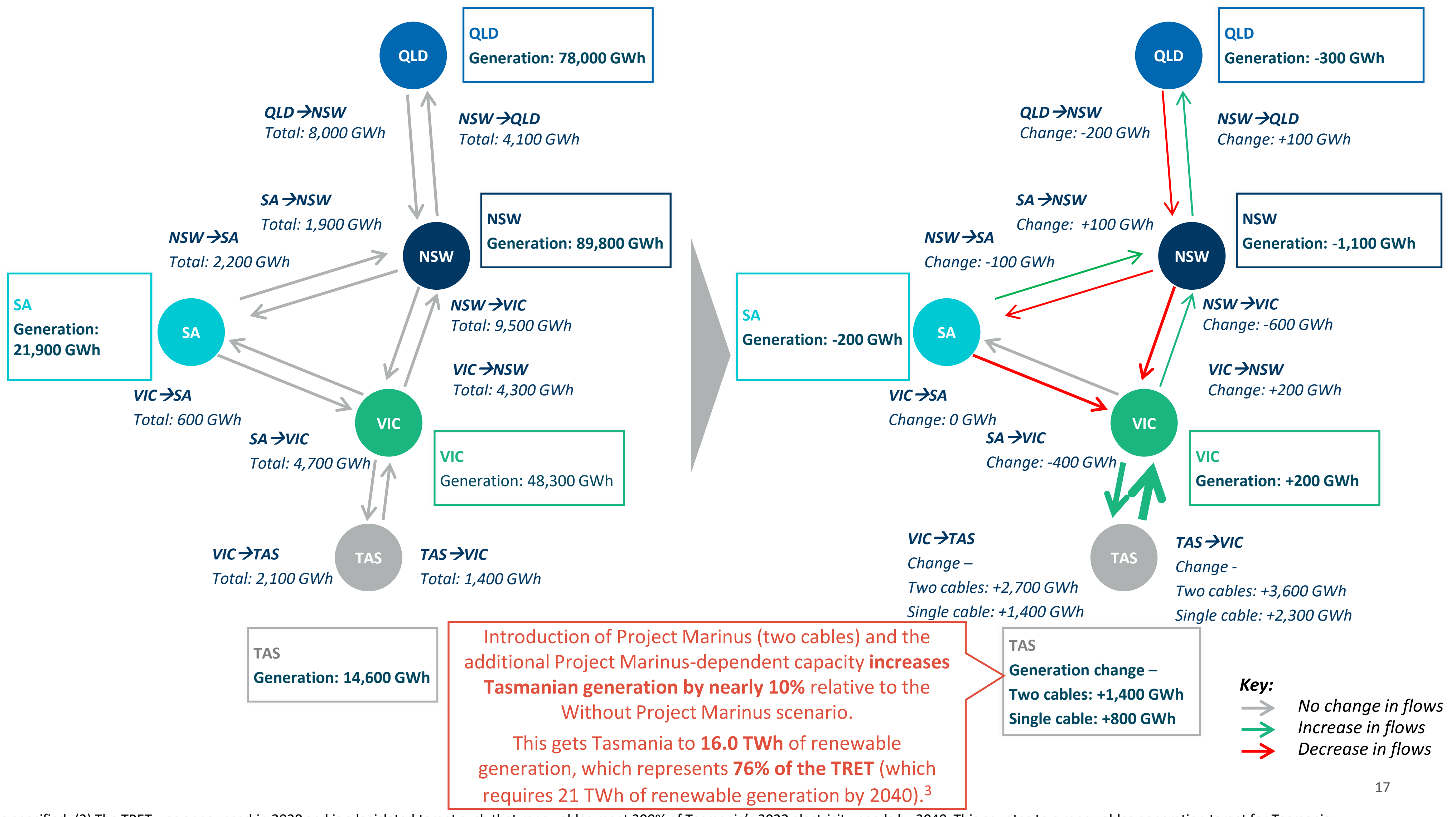
Introducing Project Marinus unlocks large volumes of renewable generation in Tasmania that would otherwise be constrained, which flows to the mainland NEM

- **In the absence of Project Marinus, Basslink**, the sole link between Tasmania and the mainland NEM, **is frequently fully utilised**. Our modelling indicates that Basslink's maximum capacity constrains exports from Tasmania in 83% of all periods modelled[1] from 2031-2050, in the absence of Project Marinus.
- During these periods, **additional Tasmanian capacity, which could help to meet demand on the mainland, is prevented from generating** by this constraint.
- Additionally, in the long run, this constraint on the ability of Tasmanian capacity to generate may potentially **weaken the commercial incentives to invest in new generation capacity in Tasmania**, such as new wind farms or Battery of the Nation. This, in turn, could threaten the ability of Tasmania to meet TRET.
- **Introducing Project Marinus reduces this constraint** which, paired with the Project Marinus-dependent capacity additions, allows large volumes of Tasmanian renewable generation to flow into the mainland NEM. For example, over calendar 2035, we estimate that **Tasmania to Victoria flows increase by 3.6 TWh as a result of a two cable Marinus.**
- In 2035, the Tasmanian renewable generation helps displace **nearly 2.5 TWh** of gas generation.[4]

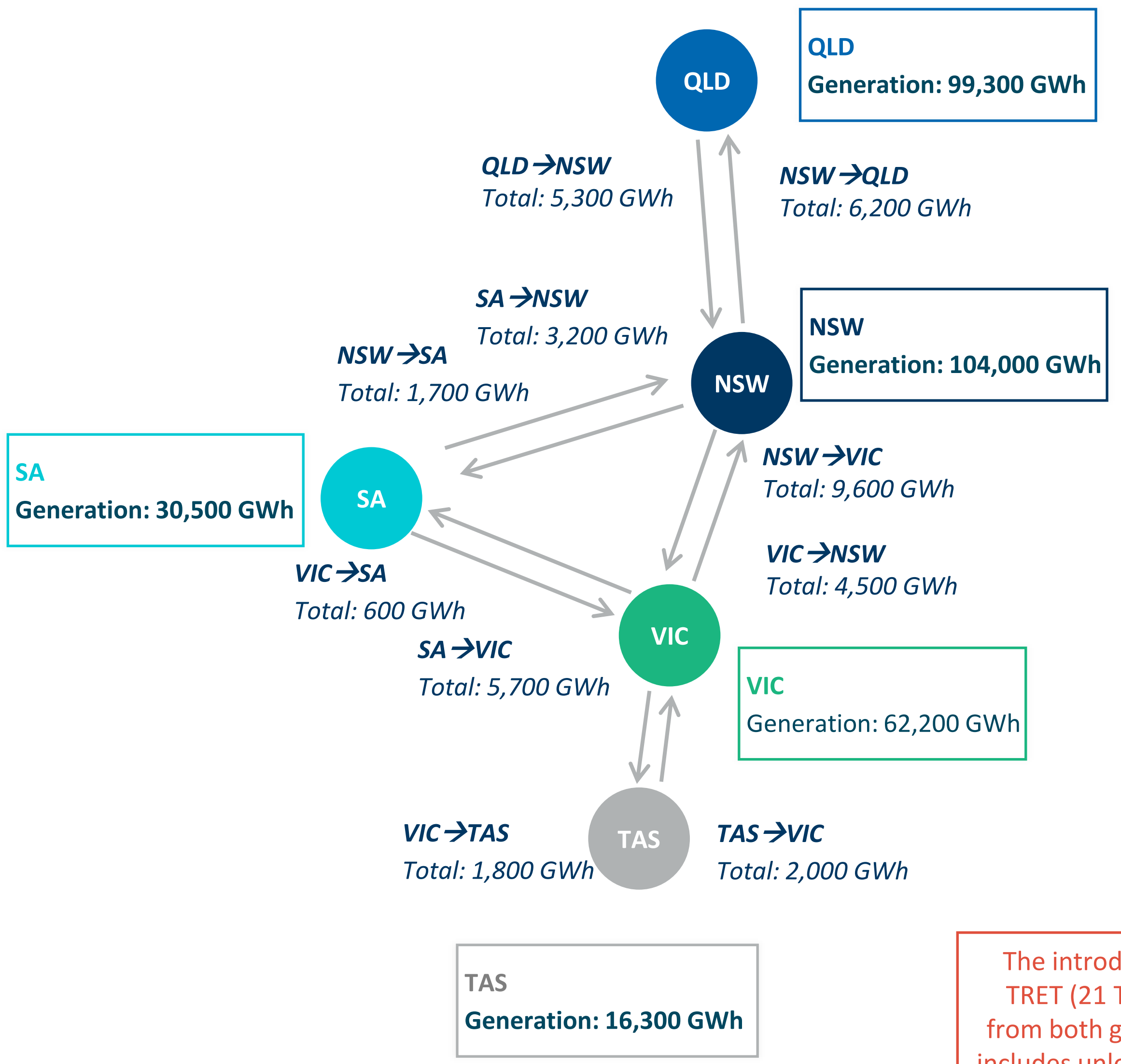
NEM topology, Without Project Marinus, 2035 | **NEM topology, With Project Marinus (two cables), FY 2035[2]**



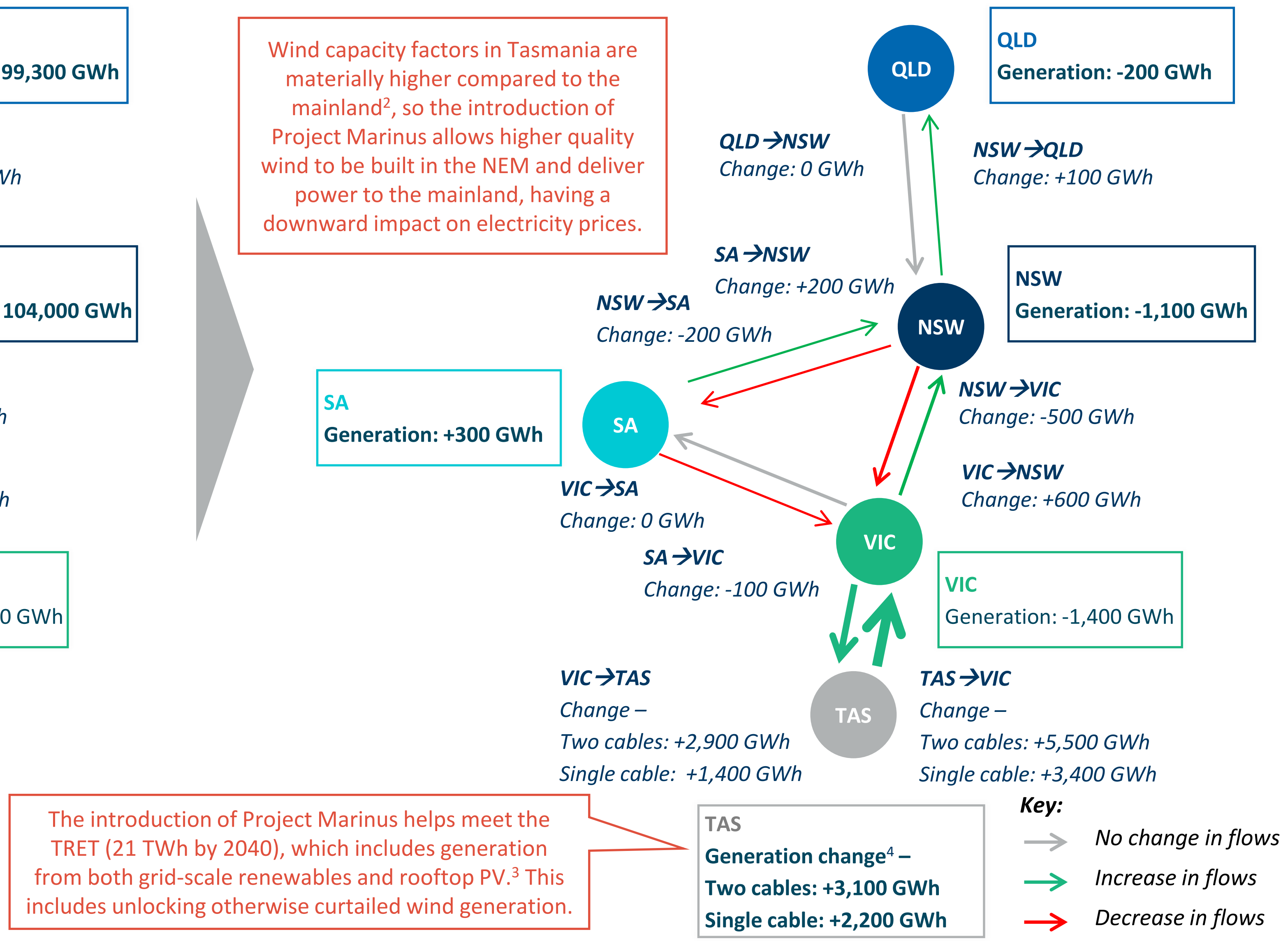
(1) We model hourly intervals. (2) All results are for two cables unless otherwise specified. (3) The TRET was announced in 2020 and is a legislated target such that renewables meet 200% of Tasmania's 2022 electricity needs by 2040. This equates to a renewables generation target for Tasmania of 21 TWh in 2040. See *The Draft Tasmanian Renewable Action Plan 2020* (link), page 4. (4) For further detail, see *Change in NEM generation when Project Marinus is introduced* chart on page 20.

Introducing Project Marinus unlocks large volumes of renewable generation in Tasmania that would otherwise be constrained, which flows to the mainland NEM

NEM topology, Without Project Marinus, 2045



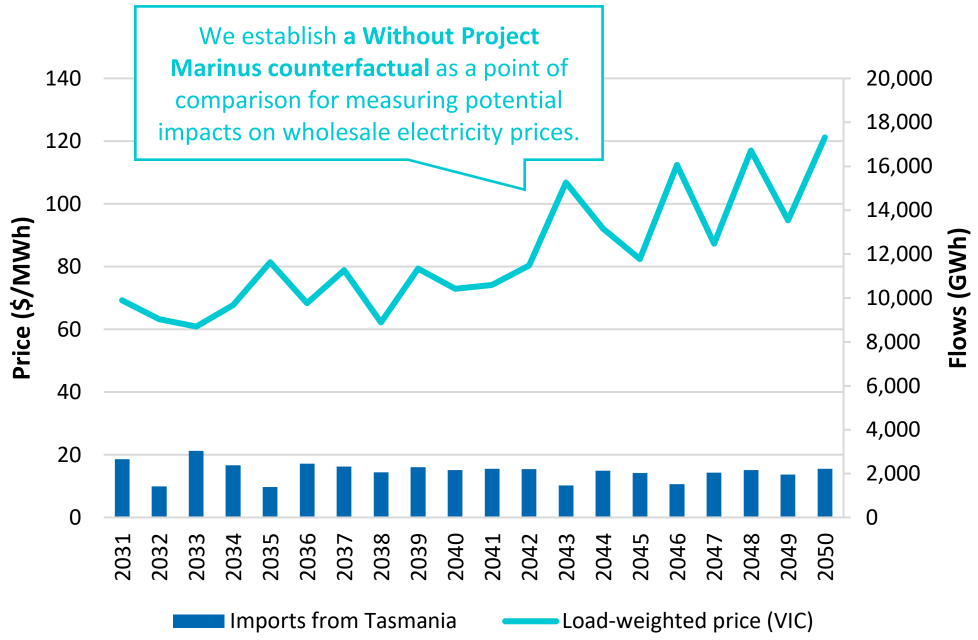
NEM topology, With Project Marinus (two cables), 2045[1]



(1) All results are for two cables unless otherwise specified. (2) AEMO, *2023 IASR Assumptions Workbook*, August 2023 (link). (3) 2023 IASR estimates c. 1.2 TWh output in 2040, which contributes to meeting TRET in combination with generation shown in chart above. (4) Net generation change due to Project Marinus is +700 GWh in 2045 due to overall additional losses introduced into the system from both interconnectors and storage assets. The change in losses in the system may differ from year to year and could be both net positive or net negative.

Project Marinus results in increased flows from Tasmania to Victoria, which aligns with a downward effect on wholesale electricity prices in Victoria

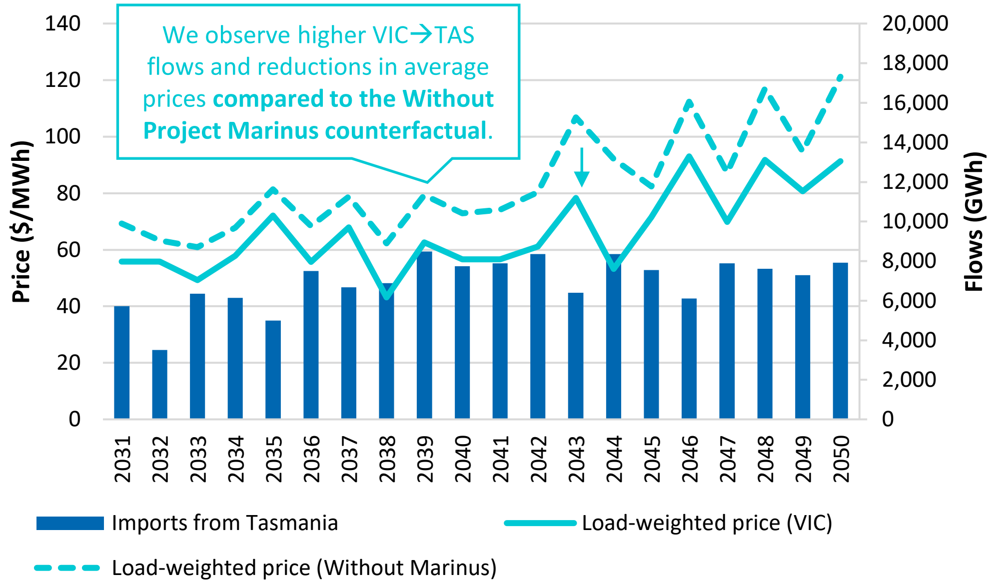
Prices ($/MWh) and Imports from Tasmania to Victoria, Without Project Marinus



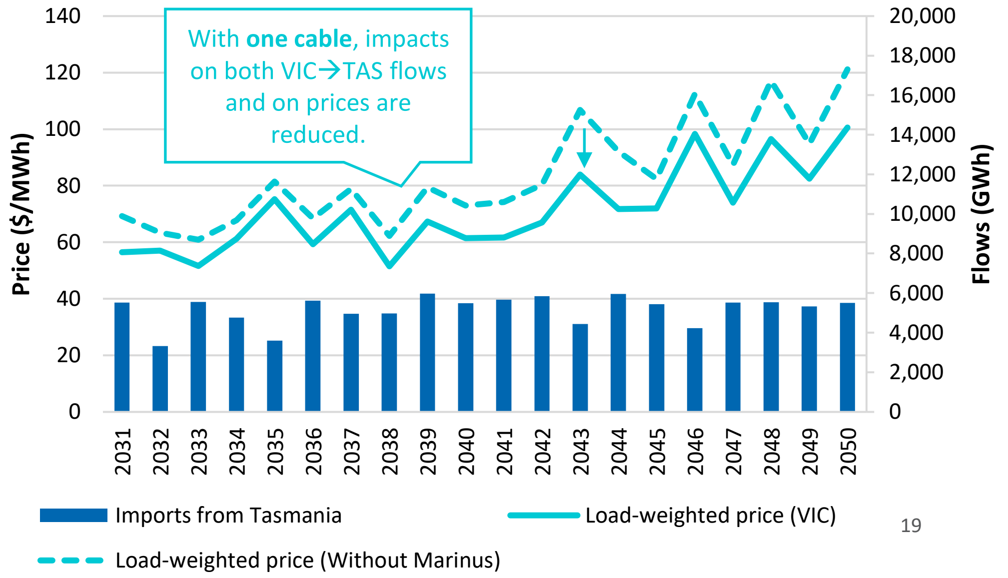
- As mentioned previously, **in the absence of Project Marinus, Basslink** is the sole link between Tasmania and Victoria.
- For Victoria, this means that there is limited capacity to import electricity from Tasmania. Our modelling indicates that **in the absence of Project Marinus**, interconnector flows from Tasmania to Victoria average **2.1 TWh per annum**.
- Over the period 2031 to 2050, our modelling indicates average load-weighted prices in Victoria of **$83/MWh.**
- Our modelling indicates prices trending upwards over time, reaching an average of **$107/MWh** in the last five years of the modelling period, compared to **$69/MWh** in the first five years.
- This serves as our **Without Project Marinus counterfactual**, against which we measure the potential impact of Project Marinus (both two cables and one cable).

Prices ($/MWh) and Imports from Tasmania to Victoria, With Project Marinus

- With the introduction of Project Marinus, the capacity to import electricity from Tasmania to Victoria increases.
- We can observe the effect of this increased capacity in our modelling of the NEM **With Project Marinus (two cables),** where interconnector flows from Tasmania to Victoria average **7.0 TWh per annum.**
- Increased flows from Tasmania to Victoria are aligned with lower average prices in Victoria of **$66/MWh** across the period – a fall in average prices of **$17/MWh compared to the Without Project Marinus counterfactual.**



- For **one cable**, capacity to import from Tasmania to Victoria is reduced compared to **two cables.**
- This impacts the levels of imports we observe in our modelling, with average flows of **5.2 TWh per annum**.
- This is still, however, a material increase in imports from Tasmania to Victoria **compared to the Without Project Marinus counterfactual.**
- Consequently, average prices across the period are still expected to fall by around **$13/MWh** compared to the Without Project Marinus counterfactual.

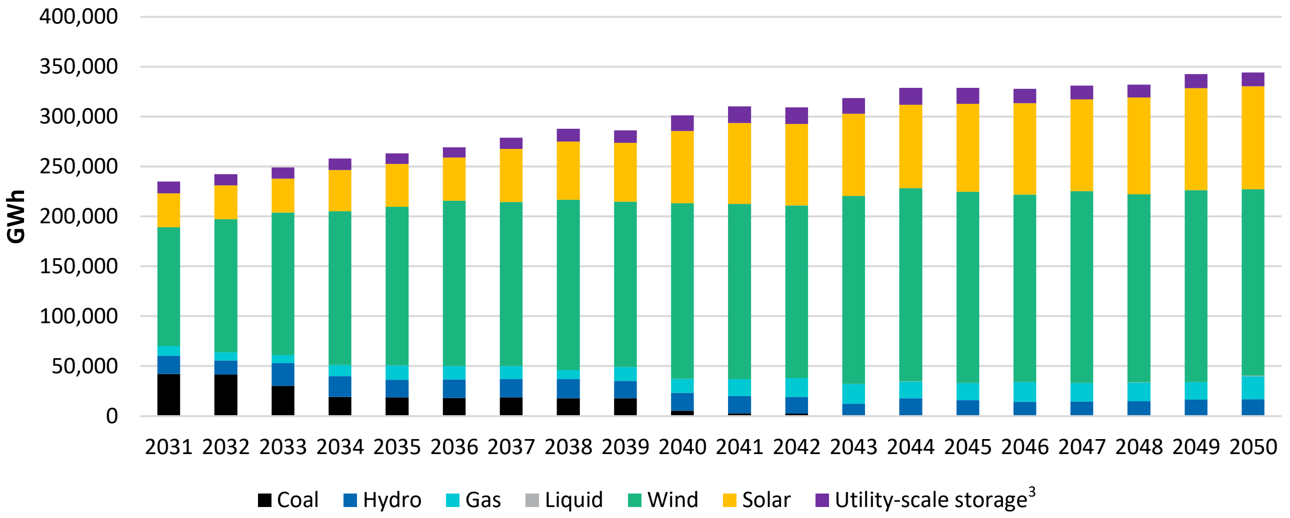


With coal retirements forecast until 2043, introducing Project Marinus and dependent capacity helps firm up supply whilst allowing more displacement of thermal gas generation with lower cost renewables

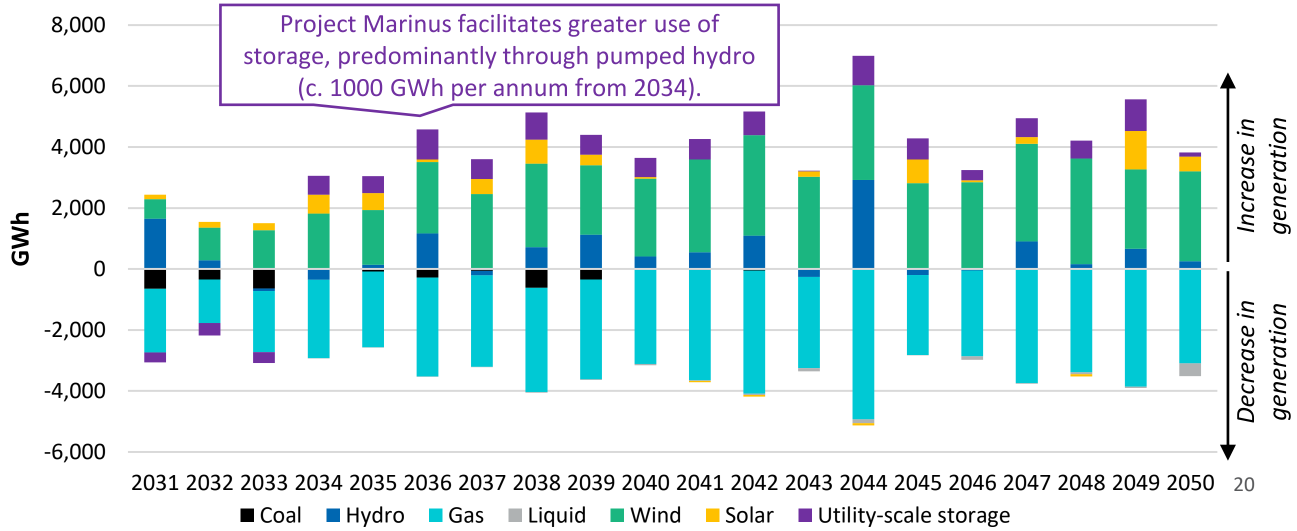
The impact of Project Marinus on NEM generation[1]

- **In the Without Project Marinus counterfactual**, gas generators are increasingly used to cover periods of relatively low renewable generation, as coal plants are retired and NEM-wide demand increases.
  - In these instances, costlier gas generators are increasingly the marginal bidders, increasing electricity prices across NEM regions.
  - Annual coal generation reduces from a level of **54 TWh per annum** in 2030, before being retired by 2043. Over the same period, gas generation increases by 135% from **8.4 TWh** to **19.8 TWh**.
- Project Marinus facilitates the entry of large volumes of Tasmanian generation into the NEM.
  - From 2033 onwards, with Project Marinus, wind generation is expected to increase, on average, by **2.6 TWh** a year, while hydro generation increases by **0.5 TWh** a year.
  - In addition to the Project Marinus-dependent wind capacity, the added export capacity of the Marinus Link cable(s) enables **reduced curtailment in Tasmanian wind** that would have been built even in the absence of Project Marinus to contribute towards the TRET.
- This has a noticeable impact on NEM-wide gas generation, as the additional interconnection capacity, combined with the additional storage capacity of Battery of the Nation, enables lower-cost renewables in Tasmania to cover periods of low renewable generation on the mainland.
  - Tasmanian wind has a high capacity factor relative to mainland wind and solar and is not strongly correlated with mainland wind generation. This complementary profile increases the share of demand that low-cost renewable generation can meet.[2]
  - The marginal gas peaking plants are significantly displaced when both Marinus Link cables are operational, with a **decrease in gas generation between 2 TWh to 5 TWh** each year from 2033 to 2050 relative to the Without Project Marinus counterfactual.
- As discussed on page 8, coal generation is expected to be phased out more rapidly than was assumed during our 2020 analysis. As such, more reliance is placed on relatively high-cost gas and less on relatively lower cost coal in our 2022 analysis.
- As such, **we now find that introducing Project Marinus and additional Project Marinus-dependent capacity displaces significantly more gas generation than in 2020** (an average of 4.1 TWh a year from 2031 to 2040 vs 2.4 TWh in 2020), and less coal.

NEM generation without Project Marinus



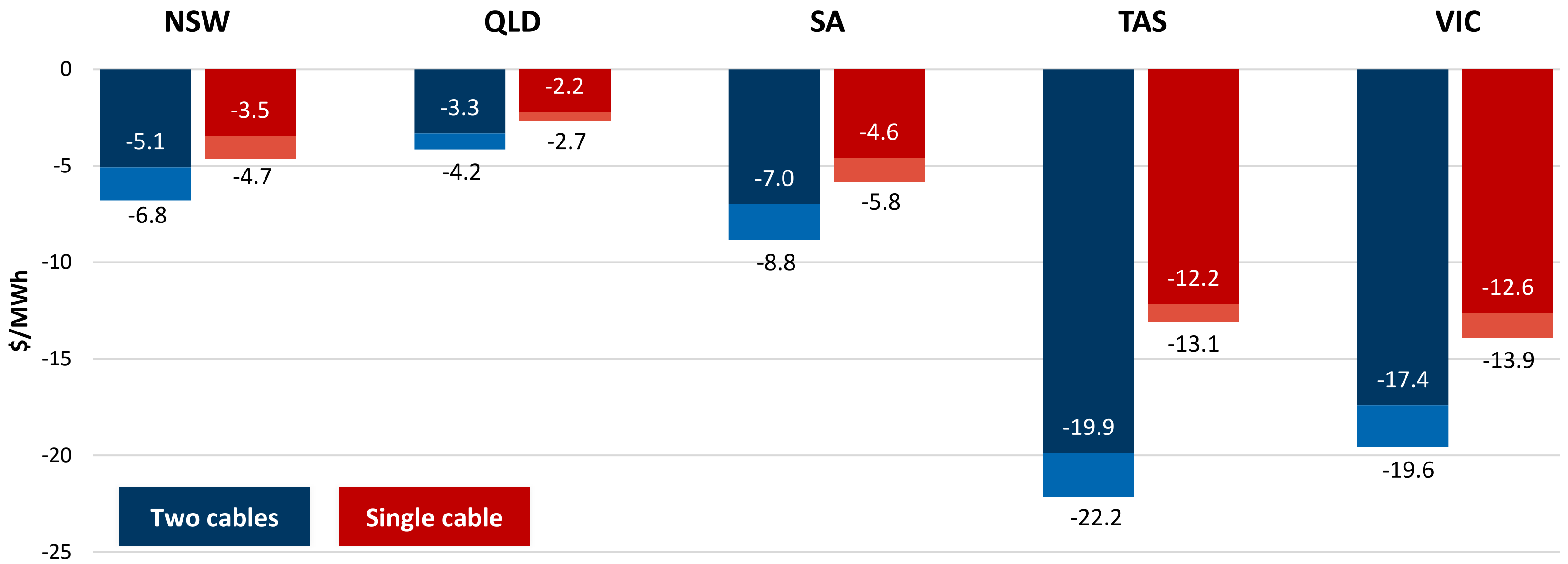
Change in NEM generation when Project Marinus is introduced



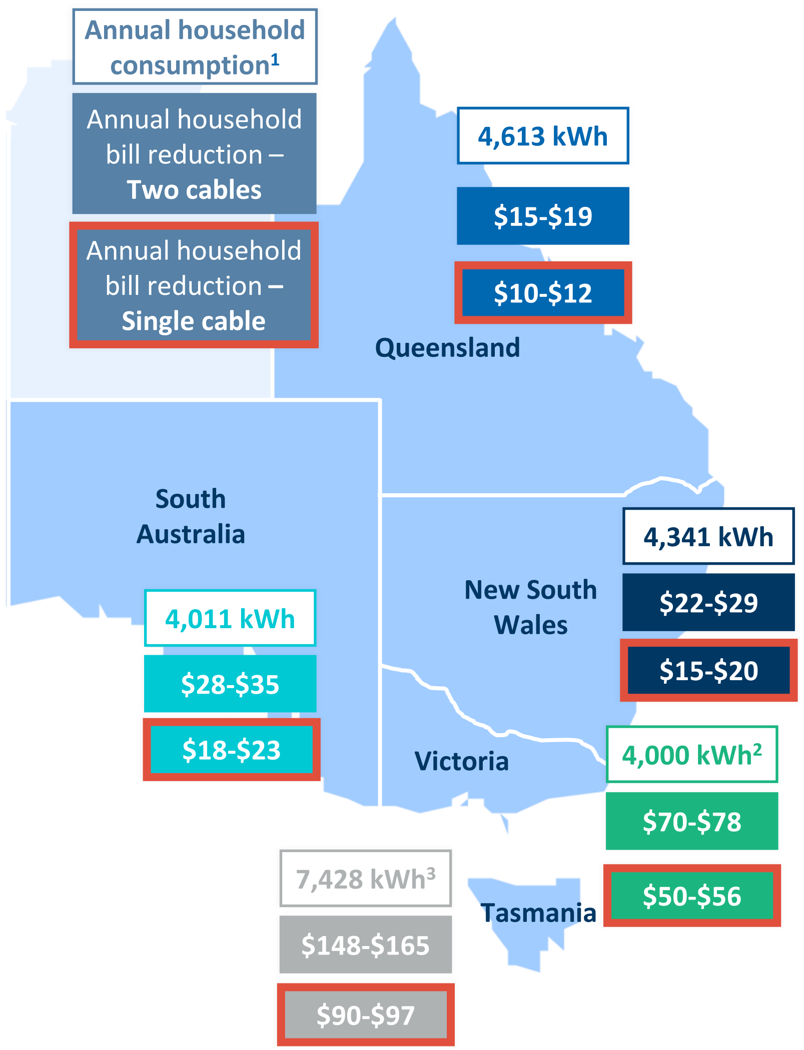
(1) All figures are for two cables unless otherwise specified. (2) Australian Energy Council, *Integrating Renewables: An assessment of Generation Correlation*, 27 September 2019 (link). (3) Utility-scale storage includes both grid-scale batteries and closed-loop pumped hydro (excludes pumped hydro with inflows). The chart presents discharge for storage assets. Charging of storage is excluded from the chart.

Our modelling once again indicates that Project Marinus is expected to lower average electricity prices across the NEM, with the impact being most significant in Tasmania and Victoria

Average reduction in wholesale prices, 2031-2050 (2023 dollars)



Household bill impact of reduced wholesale prices



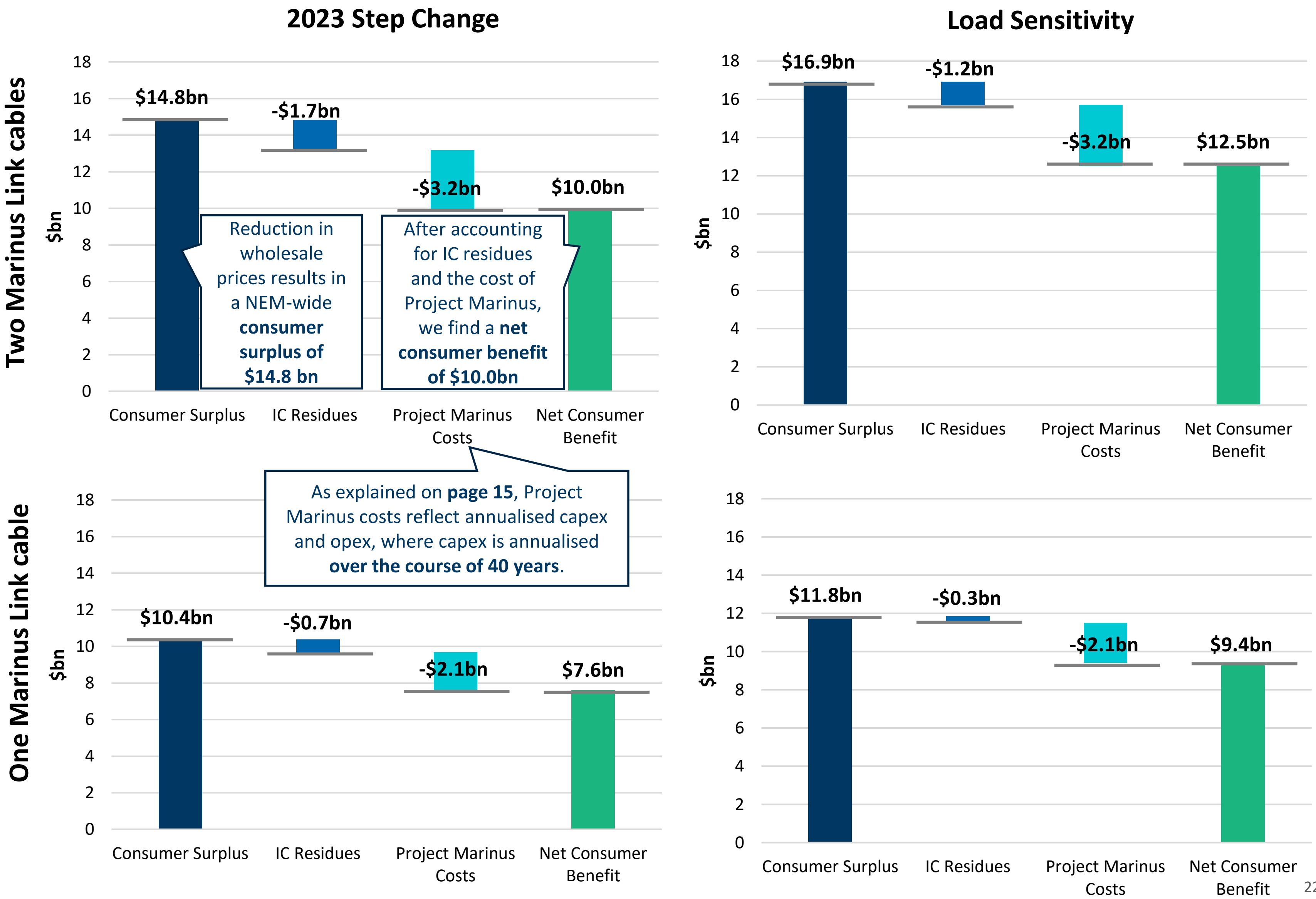
- The average expected reduction in wholesale prices is **$20 to $22/MWh for Tasmania** and **$17 to $20/MWh for Victoria** across the period 2031-50.
- In the event that only the first Marinus Link cable is constructed, the effect on prices reduces to **$12 to $13/MWh for Tasmania** and **$13 to $14/MWh in Victoria.**
- Lower electricity prices **feed directly into the wholesale energy element of consumer bills**. For **two cables**:
  - **Tasmanian consumers** expected to experience the highest savings of **$148 to $165** per household per year, driven by the relatively high level of household consumption and change in price. This falls to **$90 to $97** for one cable.
  - **Victorian consumers** experience a similar level of price change, but a lower household saving of **$70 to $78** due to lower levels of average household consumption. This falls to **$50 to $56** for one cable.
  - **In other states**, the average reductions range from **$15 to $35** per household.
- These savings are comparable to our previous work from 2022: **$111 for Tasmania** and **$72 for Victoria** in 2021 dollars (Note that this assessment looked at the average impact over a different period: 2029 to 2040).

(1) For Queensland, South Australia and NSW: Australian Energy Regulator, *Default market offer prices 2023-24 – Final Determination,* Cost assessment model, May 2023 (link). 'Residential without CL' figures used. Customer-weighted average for NSW companies (2) Essential Services Commission, *Victorian Default Offer 2023-24: Final Decision,* May 2023, page 1 (link) (3) Office of the Tasmania Economic Regulator, *Typical Electricity Customers in Tasmania – 2022*, September 2022, page 2 (link)

Our work indicates that the benefits of Project Marinus significantly outweigh the costs to consumers, resulting in net benefit of $7.6 billion to $12.5 billion from 2031 to 2050

- Our net benefits analysis indicates that with **two cables**, Project Marinus is expected to generate, **net benefits of $10.0bn to $12.5bn for NEM consumers** in net present value terms.
- If only one Marinus Link cable is constructed, these net benefits are expected to fall to **$7.6bn to $9.4bn**.
- For both single cable and two cables cases, **benefits are higher under our Load Sensitivity scenario** where Tasmanian demand is lower.[1]
  - Lower demand in Tasmania facilitates greater flows from Tasmania to Victoria: our modelling indicates increases of **17%** and **16%** for single cable and two cables respectively.
  - Therefore, in the event that Tasmania demand does not reach the levels expected under the 2023 IASR Step Change scenario, Project Marinus may be expected to generate greater net benefits across the NEM.
- This compares with estimated net benefits of **$5.4bn** for two cables from our 2020 report (in 2020 dollars). The net benefits have increased in the current modelling, driven by a number of factors:
  - faster exit of coal fired generation and faster uptake of renewables increases the demand for Tasmania renewable generations and the value of firming provided by Tasmania hydro and pumped hydro.
  - Capacity factors for Tasmanian wind generation have increased relative to the 2020 ISP.[2]
  - Fuel prices have increased, reflecting changing market conditions and inflation.

Net consumer impact of Project Marinus, $bn, Present Value 2031-2050 (2023 dollars)[3]



(1) Demand is lower across the NEM in our Load Sensitivity scenario, but the reduction in Tasmania is greater than, on average, across the rest of the NEM. This is in line with expected demand in 2023 IASR Progressive Change Scenario, on which our assumptions for the Load Sensitivity scenario builds on. (2) AEMO, *2023 IASR Assumptions Workbook*, August 2023 (link). (3) Figures shown may not sum exactly due to rounding.

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