Appendix 6. Cost-Benefit Analysis

June 2024

Appendix to the 2024 Integrated System Plan for the National Electricity Market

Important notice

Purpose

This is Appendix 6 to the 2024 Integrated System Plan (ISP) which is available at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp. AEMO publishes the 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 1 May 2024 unless otherwise indicated.

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Version control

Version	Release date	Changes
1	26/6/2024	First release

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Executive summary

AEMO's *Integrated System Plan* (ISP) is a roadmap for the transition of the National Electricity Market (NEM) power system, with a clear plan for essential infrastructure that will meet future energy needs. The ISP's optimal development path (ODP) sets out the needed generation, storage and network investments to transition to net zero by 2050 through current policy settings and deliver significant net market benefits for consumers.

This appendix provides a detailed walkthrough of the process used in this 2024 ISP to arrive at the transmission investments in the ODP, including:

- An assessment of the various transmission projects and their individual value.
- A consideration of the risks of over- and under-investment across scenarios.
- A test of the resilience of the ODP to uncertainties captured through sensitivity analysis.

It is underpinned by the consulted-on principles and methodologies in the *ISP Methodology*, updated in June 2023 following consultation, and has further benefited from consultation on the Draft 2024 ISP that was published in December 2023. It complements the generation and storage developments provided in detail in Appendix 2.

The optimal development path

The ODP covers a range of transmission, generation and storage developments. For transmission investments, the identification of projects as actionable within the ODP will lead to further action by each network proponent.

This appendix shows that the set of actionable projects (in Table 1) facilitates the transition to a low-emissions energy system while lowering cost to consumers.

The ODP presented in the 2024 ISP includes those projects classified as actionable in the Draft 2024 ISP, and has identified five additional actionable projects as after lower cost options were identified than were originally assessed.

Table 1 Actionable projects in the optimal development path

Already actionable projects (confirmed in this ISP as continuing to be actionable)	In service timing advised by proponent	Full capacity timing advised by proponent[A]	Actionable framework
HumeLink	Northern: July 2026 Southern: December 2026	Northern: July 2026 Southern: December 2026	ISP
Sydney Ring North (Hunter Transmission Project)	December 2028	December 2028	NSW[B]
New England REZ Network Infrastructure Project (New England REZ Transmission Link)	June 2031[E]	June 2031[E]	NSW[B]
Victoria – New South Wales Interconnector West (VNI West)	December 2028	December 2029	ISP
Project Marinus[C]	Stage 1: June 2030 Stage 2: June 2032	Stage 1: December 2030 Stage 2: December 2032	ISP
Newly actionable projects (as identified in this ISP)	**Earliest feasible in service timing**	**Full capacity timing advised by proponent[A]**	**Actionable framework**
Hunter-Central Coast REZ Network Infrastructure Project (Hunter-Central Coast REZ Expansion)	July 2027	July 2027	NSW[B]
Sydney Ring South	September 2028	September 2028	ISP
Gladstone Grid Reinforcement	March 2029	March 2029	QLD[D]
Mid North South Australia REZ Expansion	July 2029	July 2029	ISP
Waddamana to Palmerston transfer capability upgrade	July 2029	July 2029	ISP
Queensland SuperGrid South	September 2031[F]	September 2031[F]	QLD[D]
Queensland – New South Wales Interconnector (QNI) Connect	April 2032	March 2033	ISP

Note. Details of these projects are found in Appendix 5.
A. The capacity release and timing is conditional on availability of suitable market conditions and good test results.
B. These are actionable New South Wales projects rather than actionable ISP projects. They will progress under the *Electricity Infrastructure Investment Act 2020* (NSW) rather than the ISP framework.
C. Project Marinus is a single actionable ISP project without decision rules.
D. These Queensland projects will progress under the *Energy (Renewable Transformation and Jobs) Act 2024* (Qld) rather than the ISP framework.
E. This is the latest project proponent timing provided from EnergyCo for Part 1. The ISP modelling in the appendix applies a date provided to AEMO in December 2023. See Appendix 5 for more information.
F. This is the latest project proponent timing provided from Powerlink for Part 1. The ISP modelling in the appendix applies a date provided to AEMO in December 2023. See Appendix 5 for more information.

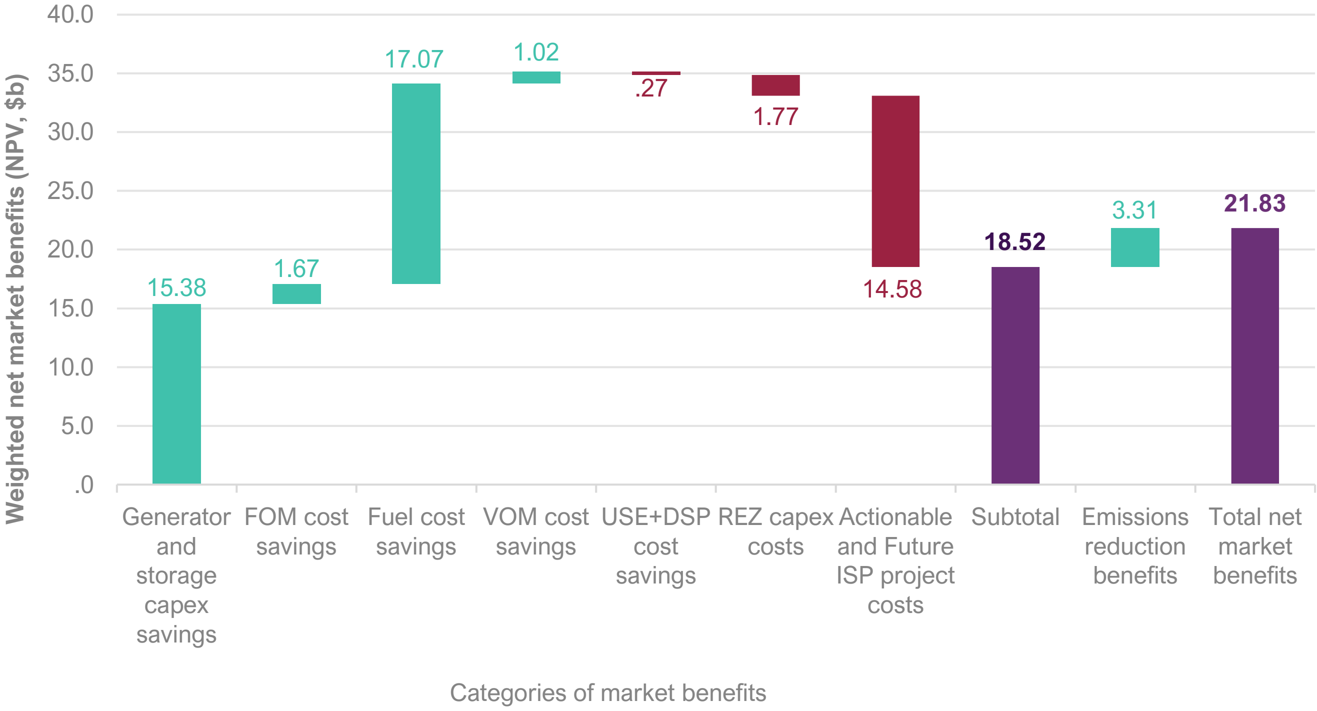
If delivered to schedule, and considering the relative likelihoods of the different scenarios that are forecast, this ODP is projected to reduce costs that the system would otherwise need to bear by the order of $18.5 billion, and to provide emissions reduction benefits valued at $3.3 billion.

As further discussed in Section A6.3, weighted net market benefits have increased slightly from the identified benefits in the Draft 2024 ISP due to a number of changes in underlying assumptions, and these benefits now include additional benefits associated with emissions reduction.

The annualised capital cost of all utility-scale generation, storage, firming and transmission infrastructure in the ODP has a present value of $122 billion in *Step Change* to 2050[1]. Transmission projects account for only $16 billion[2] or 13% of the total.

The ODP delivers balanced consideration of the risks of over- and under-investment across the scenario collection and it provides the highest weighted net market benefits across the three scenarios.

Figure 1 Components of weighted net market benefits delivered by the ODP over the outlook period to 2051-52



Note: These weighted market benefit values refer to benefits and costs accumulated to 2051-52, rather than cutting off at 2049-50.

Table 2 Top six candidate development paths (CDPs) across scenarios (in $ billion), in order of descending weighted net market benefits

CDP	*Step Change*	*Progressive Change*	*Green Energy Exports*	Weighted Net Market Benefits (WNMB	WNMB Rank	Worst weighted regrets	WWR Rank
14 (ODP)	16.66	13.64	59.60	21.83	1	0.32	13
24	16.61	13.73	59.41	21.82	2	0.28	8
5	16.96	13.84	58.08	21.82	3	0.26	4
18	16.91	13.79	58.31	21.81	4	0.26	2
21	16.67	13.68	59.27	21.80	5	0.30	11
3	16.94	13.71	58.35	21.80	6	0.29	9

[1] This value includes transmission augmentation, and utility-scale generation and storage capital expenditure, and does not include the cost of commissioned, committed or anticipated projects, consumer energy resources or distribution network upgrades. The value increased from $121 billion in the Draft 2024 ISP to $122 billion due to modelling changes listed on page 19.

[2] This value is the net present value of capital costs for transmission augmentation up to 2049-50 only, and does not include the cost of commissioned, committed, or anticipated projects.

Changes implemented since the Draft 2024 ISP

Among the changes since the Draft 2024 ISP, the inclusion of emissions reduction as a class of market benefits has the largest impact to the weighted net market benefits of the ODP, providing an additional $3.3 billion. Other changes include new committed and anticipated generation and storage developments identified in AEMO's Generation Information publication[3] as of February 2024, additional transmission development options, considerations of gas infrastructure capacity limitations, consideration of uncertainty pertaining to weather patterns, amended gas generation in the short term, inclusion of the expanded Capacity Investment Scheme (CIS) targets, and other minor changes to transmission and demand assumptions.

Sensitivity analysis confirms the choice of the ODP

AEMO's modelling demonstrates that the ODP provides appropriate resilience and robustness to future uncertainties through the use of a scenario planning approach, and assessment of individual uncertainties through sensitivity analysis. The additional sensitivities modelled in the 2024 ISP explore a range of risks and uncertainties beyond those included in the Draft 2024 ISP, including:

- Alternative assumptions around levels of coordination of consumer energy resources (CER), commitment of additional load, and electric vehicle (EV) uptake.
- Alternative assumptions around electricity supply availability and the potential challenges of delivery.
- Impact of having lower electrolyser flexibility.

As Table 3 shows, the ODP is one of the most resilient development paths compared with the collection of alternatives. It is the path that delivers the highest-ranked weighted net market benefits across six of the seven sensitivities.

Figure 2 shows the impact of each sensitivity on the weighted net market benefits for the ODP.

The 2024 ISP confirms the actionability of the projects identified in the ODP of the Draft 2024 ISP by extending the sensitivity analysis to more recent developments and risks highlighted by stakeholders from the consultation to the Draft 2024 ISP. In some instances, sensitivity analysis that was performed on the Draft 2024 ISP has not been re-simulated, as the updated model parameters were not expected to have changed the insights obtained from the Draft 2024 ISP.

[3] At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

Figure 2 Weighted net market benefits in the core scenarios and across all sensitivities, ($, billion)

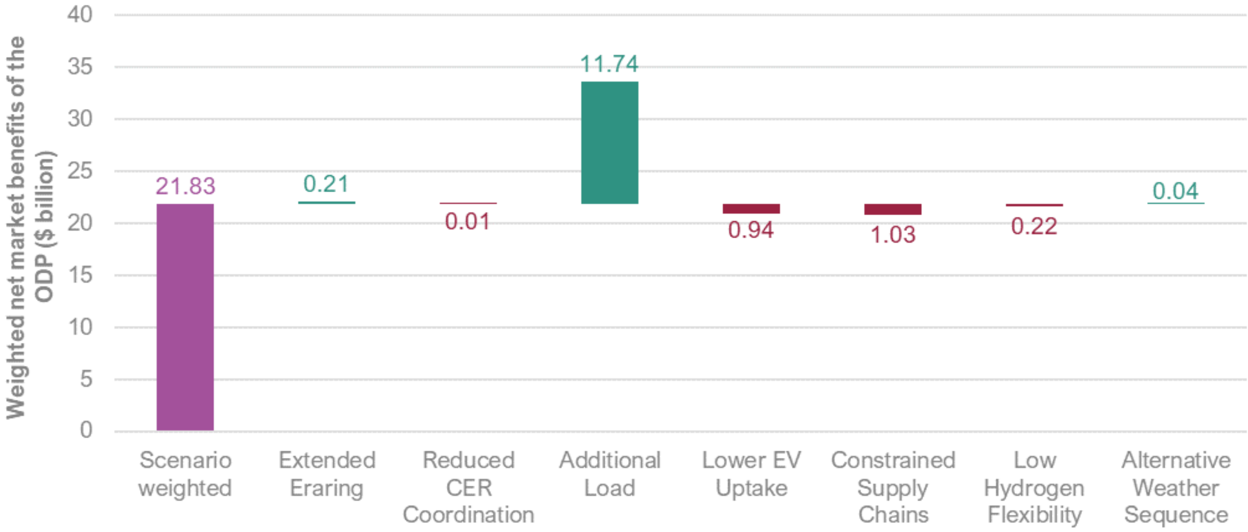


Table 3 Relativity of weighted net market benefits (in $ billion) for key CDPs across the sensitivity collection

CDP[A]	Description	Core scenarios	Extended Eraring	Reduced CER Coordination	Additional Load	Lower EV Uptake	Constrained Supply Chain[B]	Low Hydrogen Flexibility	Alternative Weather Sequence
Weighted net market benefits									
14	CDP3 with actionable Project Marinus Stage 2	21.83	22.03	21.82	33.57	20.90	20.81	21.62	21.87
24	CDP14 without actionable Queensland SuperGrid South	21.82	22.02	21.80	33.52	20.91	20.31	21.57	21.86
5	CDP3 without actionable Sydney Ring South	21.82	21.95	21.77	33.54	20.91	20.80	21.60	21.82
18	CDP3 without actionable Queensland SuperGrid South	21.81	22.03	21.76	33.49	20.93	20.31	21.55	21.80
21	CDP14 without actionable Sydney Ring South	21.80	21.99	21.79	33.54	20.86	20.78	21.58	21.85
3	*Step Change* least-cost DP	21.80	22.02	21.76	33.52	20.89	20.78	21.59	21.79
Change in weighted net market benefits relative to the most beneficial CDP									
14	CDP3 with actionable Project Marinus Stage 2	0.00	0.00	0.00	0.00	-0.03	0.00	0.00	0.00
24	CDP14 without actionable Queensland SuperGrid South	-0.01	-0.02	-0.02	-0.05	-0.02	-0.49	-0.05	-0.01
5	CDP3 without actionable Sydney Ring South	-0.02	-0.09	-0.05	-0.04	-0.02	-0.01	-0.02	-0.06
18	CDP3 without actionable Queensland SuperGrid South	-0.02	-0.00	-0.06	-0.08	0.00	-0.49	-0.06	-0.07
21	CDP14 without actionable Sydney Ring South	-0.03	-0.04	-0.03	-0.03	-0.07	-0.03	-0.03	-0.02
3	*Step Change* least-cost DP	-0.03	-0.01	-0.06	-0.05	-0.04	-0.03	-0.03	-0.08

Note: Cells shaded teal represent the top CDP for each of the sensitivities.
A. The numbering and definitions of the Candidate Development Paths (CDPs) have changed since the Draft 2024 ISP.
B. The NEM carbon budget to 2029-30 and the 82% renewable energy target by 2029-30 are both not met under this sensitivity and the costs associated with the breach of these policies are not included in the NPV calculations.

Note: Consideration of Draft 2024 ISP consultation feedback has necessitated additional transmission options, leading to additional development paths (DPs). This has required re-definition of the candidate development paths (CDPs). The CDP numbering has therefore changed since the Draft 2024 ISP.

Care must be observed when comparing results; CDP3 in the Draft 2024 ISP is not the same as CDP3 in the 2024 ISP, and the Draft 2024 ISP's ODP (CDP11) is not identical to either CDP11 in the 2024 ISP, or the 2024 ISP's ODP (CDP14).

CDP14 represents the CDP with the highest weighted net market benefits across the CDP collection, and given its robust performance across the set of alternative assumptions tested through sensitivity analysis, AEMO identifies CDP14 as the optimal development path.

A6.1 Introduction

This Appendix 6 of the 2024 ISP sets out the process and rationale for identifying the optimal development path (ODP) from a range of candidate development paths (CDPs). CDPs represent a shortlist of possible alternative transmission development paths, including each scenario's least-cost development path (DP) and several alternative development paths that perform well across the scenarios but may not be the 'best' in any given scenario.

This appendix details the cost-benefit analysis (CBA) implemented in this 2024 ISP and presents the analyses on each of the CDPs across the three ISP scenarios and across a range of alternative sensitivities.

In this appendix:

- A6.2 provides a summary of the overall approach to the CBA.
- A6.3 shows the impact of changes since the Draft 2024 ISP on the CBA.
- A6.4 steps through the process of determining the least-cost DP in each scenario.
- A6.5 outlines the development of the set of CDPs based on the least-cost DPs.
- A6.6 provides a detailed assessment of individual transmission projects, by examining their individual impact and the value that they provide by being declared as 'actionable projects'.
- A6.7 summarises the findings from A6.6 and identifies the ODP.
- A6.8 tests the resilience of the ODP and a subset of the CDP collection to several sensitivities.
- A6.9 explores impact of consumer risk preferences on transmission timings.
- A6.11 finalises the identification of the ODP after considering insights from the sensitivity analyses.
- A6.12 summarises the sensitivity analysis from the 2024 Draft ISP.

Other notes relevant to this appendix

All values presented in this appendix are on a 30 June 2023 real dollars basis unless stated otherwise. Net present value (NPV)[4] outcomes are discounted back to 30 June 2023 by applying the relevant discount rate. All NPVs consider an outlook period from 2024-25 to 2051-52, unless otherwise stated.

The cost estimates for transmission projects in this appendix represent the cost in the year of delivery, expressed in 2023 dollars. For this reason, projects will have different costs in development paths where they are delivered in different years. This reflects the application of AEMO's transmission cost forecasting approach, explained in the 2023 Transmission Expansion Options Report. These costs may appear differently to those presented in Appendix 5, which displays the cost for delivery in a fixed year.

This appendix is supported by the **Generation and Storage Outlook Workbook**[5] which also provide a breakdown of the difference in system costs between CDPs.

[4] See Section A6.2.1.

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

Key changes from the Draft 2024 ISP

AEMO has incorporated several changes since publication of the Draft 2024 ISP in response to stakeholder feedback, legislative changes, and recent market developments, including:

- Inclusion of emissions reduction as a class of market benefits by applying the Value of Emissions Reduction (VER).
- Considerations of gas infrastructure capacity limitations, and revision to short term gas generation forecasts to align with the 2024 GSOO.
- Consideration of additional uncertainty on weather patterns.
- Inclusion of the latest committed and anticipated projects as per the February 2024 Generation Information release.
- Inclusion of the expanded Capacity Investment Scheme (CIS) targets.
- Changes to earliest in-service dates (EISD) and costs of several transmission projects.
- Change in the subregional allocation of demand in New South Wales to improve the distribution of electricity consumption across the sub-regions observed historically, on average.
- Changes in hydrogen load assumptions, with load for green steel production carved out from other region's loads and modelled in Sydney, Newcastle and Wollongong subregion to reflect proposed projects.
- Changes to the modelling of Coordinated CER to improve the accounting of losses.

These changes have necessitated re-analysis of the scenarios and introduced additional potential actionable transmission augmentations since the Draft 2024 ISP for consideration.

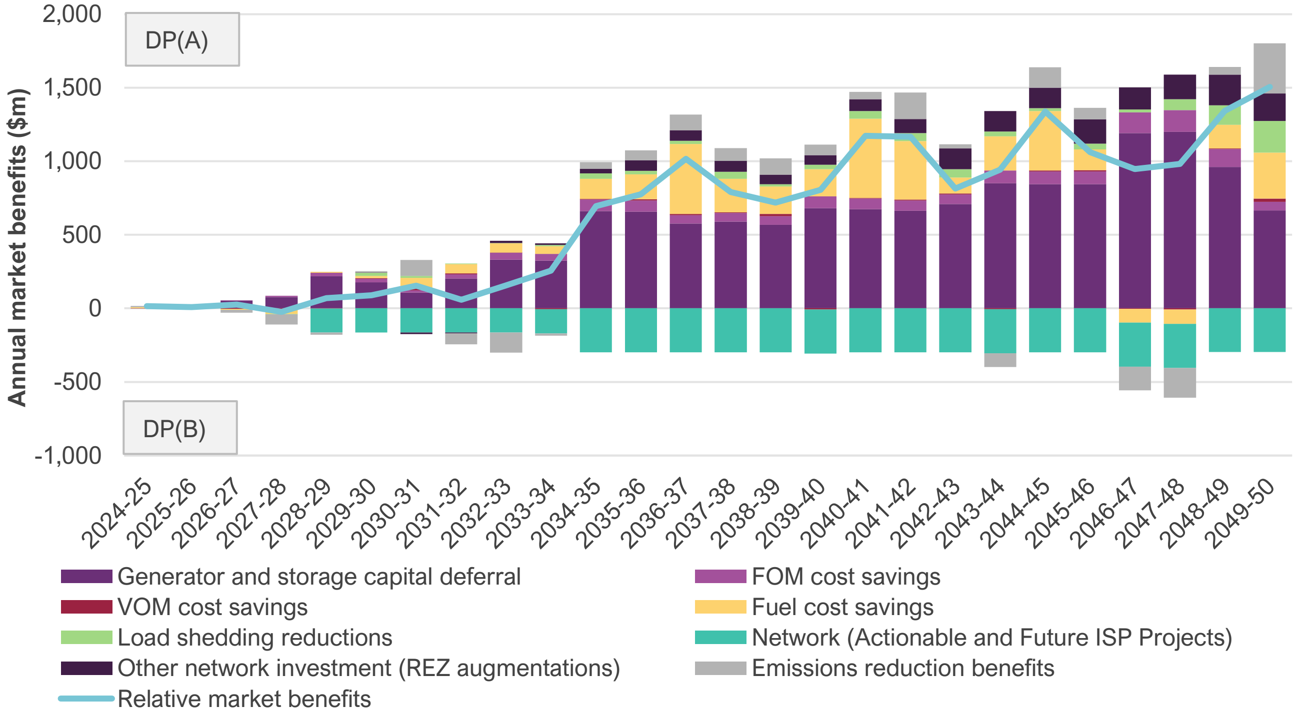
A6.1.1 Interpreting the graphics in this appendix

This appendix presents a number of charts comparing the projected benefits of two different development paths over the outlook period, as shown in Figure 3 below. When interpreting this chart:

- The stacked columns illustrate the projected values for different classes of market benefits on an annual undiscounted basis.
- Positive values indicate benefits (cost savings) associated with DP(A) relative to DP(B) and negative values indicate the additional costs incurred compared to DP(B). For example, the dark purple bars above the x-axis represent generation capital deferral cost savings in DP(A), while the turquoise bars below the x-axis indicate greater transmission costs in DP(A) compared to DP(B). In some cases, the secondary DP may be the 'counterfactual DP', which refers to a future development path with no new major transmission augmentation developed.
- The blue line represents the projected annual market benefits of DP(A) over DP(B). Where the line is above the x-axis, DP(A) delivers positive net market benefits relative to DP(B) for that specific year. Conversely, where the line is below the x-axis, DP(A) delivers negative net market benefits relative to DP(B) in that year.

- Fixed operating and maintenance (FOM) and variable operating and maintenance (VOM) cost savings are abbreviated in the legend, while load shedding reductions refers to costs associated with changes in voluntary and involuntary load shedding.

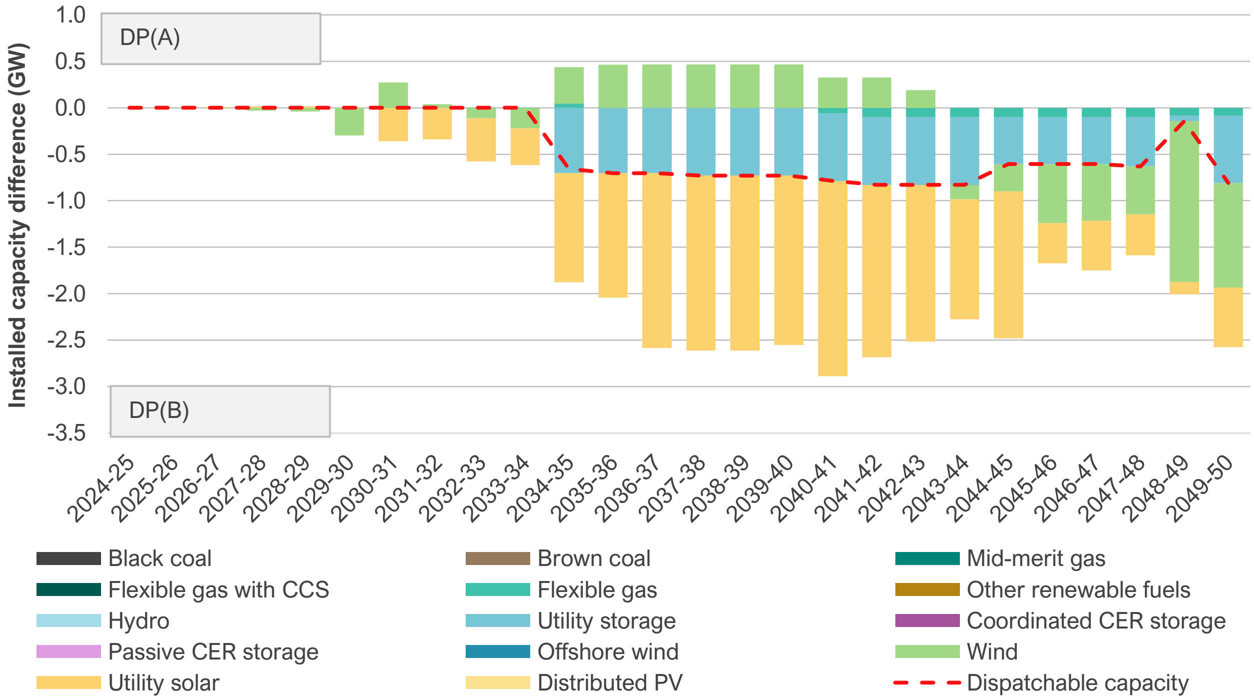
Figure 3 Example interpretation of annual market benefits used in this appendix



This appendix also presents charts comparing the projected capacity and generation differences over the outlook period of two different development paths, as shown in the example figure below. When interpreting the sample chart in Figure 4:

- The stacked columns show the projected values (capacity or energy generated) for different technologies on an annual basis.
- The values reflect the relative difference between the two modelling outcomes. A positive value indicates the higher total capacity (or generation) in DP(A) relative to DP(B) and a negative value indicates higher capacity (or generation) in DP(B). For example, the yellow bar indicates there is higher capacity of utility solar in DP(B) relative to DP(A).
- The line represents the projected difference in total dispatchable capacity between the two modelling outcomes. Dispatchable capacity refers to generation and storage capacity that can adhere to dispatch instruction, being controllable and flexible, and can provide greater certainty on its availability.
- 'Distributed PV' described in this appendix refers to the combination of rooftop PV and other distributed solar generation (which is used as the equivalent descriptor in the primary Draft 2024 ISP report).

Figure 4 Example interpretation of forecast capacity differences used in this Appendix



While the ISP modelling horizon covers an outlook period until 2051-52, for the purpose of the report, outcomes are presented until 2049-50.

A6.2 Approach to the cost-benefit analysis

A6.2.1 The ISP approach to cost-benefit analysis

The 2024 ISP applies AEMO's *ISP Methodology*[6], which details the approach used in the modelling and CBA that underpins the identification of the ODP. The updated *ISP Methodology* was developed in accordance with the Australian Energy Regulator's (AER's) *Forecasting Best Practice Guidelines* and *Cost Benefit Analysis Guidelines*[7]. It sets out the following principles that govern the following aspects of the CBA:

- The quantification of costs and classes of market benefits that are considered in this ISP.
- The determination of the least-cost DP for each scenario (Step 1 of the CBA).
- The evaluation of net market benefits compared with the counterfactual DP[8].
- The process for building CDPs (Step 2).
- The process for assessing the CDPs across all scenarios (Step 3).
- The process for ranking CDPs according to weighted net market benefits (WNMB) and worst weighted regrets (WWR)[9] (Steps 4 and 5).
- Identifying the ODP after considering sensitivity analysis (Step 6).

The Glossary provides a number of important definitions for this Appendix. Other key terms specifically used in this appendix are summarised below for reference. Terms defined in the NER, AER guidelines or the *ISP Methodology*[10] have the meanings given in those documents:

- The **earliest in-service date (EISD)** of a project is the earliest date the project can be completed.
- An **actionable window** is a period of time within which the delivery of a project is optimal for it to be considered actionable.
  - For new actionable projects, the length of the actionable window is two years, which practically means that if the project is not required until two years after the EISD, it can wait two years to be actioned if still required in the next ISP.
  - For projects that were first actioned in the previous ISP, they retain actionable status if required in the four-year period starting at the EISD. This reflects that a project that was actioned in a previous ISP has been progressing for at least two years (including regulatory approvals) and delaying the project would likely 'reset' it, requiring re-work of the progress made, leading to longer lead time delays. The window is

[6] At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/isp-methodology-2023/isp-methodology_june-2023.pdf?la=en.

[7] At https://www.aer.gov.au/system/files/AER%20-%20Cost%20benefit%20analysis%20guidelines%20-%2025%20August%202020.pdf.

[8] In the CBA, net market benefits reflect the difference in discounted total system costs of a given DP relative to a counterfactual DP (for net market benefits) or another alternative DP (for relative market benefits).

[9] The *ISP Methodology* refers to the 'least-worst weighted regret'; the worst-weighted regret approach described in this appendix is identical to that described in the methodology. This appendix describes the approach for ranking CDPs as ranking in accordance with the worst weighted regret, to find the CDP that provides the least-worst weighted regret.

[10] At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/isp-methodology-2023/isp-methodology_june-2023.pdf?la=en, pp.80-81.

used to assess whether a project that was previously actionable should retain its actionable status from one ISP to the next.

 – For projects that have been actionable for multiple ISPs, the length of the actionable window is two years (to reflect the time period before the next ISP) plus two years for each ISP (excluding ISP updates) in which those projects were declared as actionable.

- **Potential actionable and future ISP projects** share the definitions for actionable and future ISP projects outlined in the Glossary, except these concepts appear before the identification of the ODP.
- A **minimum-regret project** is defined as being a potential actionable ISP project in all scenarios.

For the assessment of costs and benefits:

- **Net present value (NPV)** is the discounted sum of all costs and is used to determine the discounted total system cost of each DP.
- **Relative market benefits** reflect the difference in discounted total system costs of a given DP relative to another alternative DP.
- A CDP's **weighted net market benefits** (WNMB) reflect the weighted average of a CDP's net market benefits across all scenarios. Net market benefits are weighted based on likelihoods derived in consultation with stakeholders via the Delphi Panel (see Appendix 1).
- A **CDP's worst weighted regrets** reflect the highest amount of weighted 'regrets' (which is the difference in net market benefits between the CDP that has the highest net market benefits and the CDP of interest under the same scenario) across the scenarios. The worst weighted regrets are associated with risks of over- or under-investment.

A6.2.2 Application of scenario weightings to net market benefits and worst weighted regrets

Table 4 shows the scenario weightings determined by AEMO, considering the insights from stakeholder consultation using a Delphi process (see Appendix 1). These weightings are applied to both net market benefits and worst weighted regrets associated with each CDP in the CBA analysis to allow comparison of CDPs across the set of scenarios.

Table 4 Scenario weightings applied in the cost-benefit analysis

Scenario	Weighting
Step Change	43%
Progressive Change	42%
Green Energy Exports	15%

Classes of market benefits

The National Electricity Rules (NER) set out the classes of market benefits that must be considered in the ISP. The 2023 *ISP Methodology* provides more detailed information on how these relate to the CBA Assessment. The classes of market benefits included in AEMO's CBA assessment include:

- Benefits related to the development and operational costs of generation and storage assets:
  - Changes in fuel consumption arising through different patterns of generation dispatch.
  - Changes in costs for parties due to the timing of new plant, differences in capital costs, and differences in operating and maintenance costs
- Development and operational costs of transmission assets:
  - Differences in the timing of expenditure, and in operating and maintenance costs.
- Costs associated with demand reduction due to changes in voluntary load curtailment (through demand side participation (DSP)), and involuntary load shedding costs, valued at the value of customer reliability.
- Costs associated with changes in greenhouse gas emissions, valued at the value of emissions reduction.

Several classes of market benefits are not explicitly accounted for above, and are instead considered as follows:

- Changes in network losses:
  - To some extent, differences in losses attributed to differences in interconnector flows and loss equations are accounted for in the changes to fuel and operating costs of assets, given they are calculated dynamically.
  - Changes in intra-regional losses arising across alternative DPs are not necessarily captured by the interconnector loss equations.
- Option value is captured through the assessment of flexibility in DPs, and the approach to identifying the ODP.
  - Changes in ancillary service costs and competition benefits are not considered as part of the CBA analysis by default, given the challenge in quantifying them across all alternative DPs.

A6.3 Impacts of the changes since the Draft 2024 ISP

The 2024 ISP reflects a number of changes in assumptions since the Draft 2024 ISP to capture updated information and stakeholder feedback.

This section covers the impacts of the main set of changes that have been implemented since the Draft 2024 ISP on the costs and net market benefits. It mirrors Section A2.2 in Appendix 2, which covers their impacts on the generation and storage development opportunities.

Inclusion of emissions reduction benefits

Emissions reduction benefits have been incorporated as an additional class of benefits using the methodology for deriving an interim Value of Emissions Reduction (VER) agreed by Energy Ministers in February 2024[11], and in accordance with the CBA guidelines and *ISP Methodology*[12]. This new benefit class reflects the appropriate consideration of the amendments to the national electricity objective (NEO)[13] and NER[14], and is consistent with the guidance provided by the AER[15].

Consideration of the existing gas infrastructure's capacity limitation

To better represent limitations of the gas system to supply fuel on-demand at all times for gas-powered generators (GPG), AEMO has incorporated additional daily gas consumption limits to reflect the historical availability of gas for electricity generation purposes. In addition, to ensure a reliable and resilient fuel supply under most conditions, AEMO has included an additional cost of on-site secondary fuel storage, and uses secondary fuels if required when gas supply is constrained (for GPG in southern regions). This approach has not applied to Queensland gas generators, as gas infrastructure in that region is less affected by infrastructure constraints and declining gas availability.

This consideration of the existing gas infrastructure's capacity to provide gas for electricity generation in New South Wales, South Australia, Tasmania and Victoria has two related impacts on the total system cost and consequently on net market benefits. It reduces GPG operating levels, by reflecting gas limitations more explicitly, and it captures an increase in fuel costs when GPGs are operated on secondary fuels when gas infrastructure limitations constrain gas supply.

This consideration was only applied in *Progressive Change* and *Step Change* because applying it in *Green Energy Exports* would be internally inconsistent with the narrative of that scenario – that is, the scenario's narrative explores a fast transition to net zero by 2050, and this includes broad infrastructure development to enable a

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[11] At https://www.aemc.gov.au/sites/default/files/2024-03/Attachment%204%20VER%20MCE%20Statement%20for%20Commission%20200324.pdf.

[12] At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/isp-methodology-2023/isp-methodology_june-2023.pdf?la=en.

[13] See https://www.energy.gov.au/energy-and-climate-change-ministerial-council/working-groups/energy-governance-working-group/incorporating-emissions-reduction-objective-national-energy-objectives.

[14] See the Australian Energy Market Commission's (AEMC's) rule change to harmonise the national energy rules with the updated NEO, at https://www.aemc.gov.au/rule-changes/harmonising-national-energy-rules-updated-national-energy-objectives-electricity.

[15] See AER guidance on valuing emissions reduction, at https://www.aer.gov.au/industry/registers/resources/guidelines/valuing-emissions-reduction-final-guidance-may-2024.

hydrogen and renewable gas opportunities, therefore it is reasonable to expect that gas infrastructure that supports GPG operations also expands in the scenario.

AEMO has observed that in the counterfactual scenario when transmission augmentations are not developed, gas infrastructure investments are a necessary substitute, to achieve the alternative path to net zero that does not rely on hosting new renewable energy projects outside of the existing transmission network. In the counterfactual, greater reliance on gas, including gas generation with carbon capture and sequestration, is forecast, resulting in a greater reliance on gas infrastructure investments. As such, the counterfactual does assume a higher forecast daily gas production limit in *Progressive Change* and *Step Change* to represent gas infrastructure developments in lieu of transmission network upgrades. This is further discussed in Section A.2.2 of Appendix 2.

Consideration of uncertainty pertaining to weather pattern

Stakeholders raised concerns with the significance of the role that gas was forecast to play in the Draft 2024 ISP, especially the new developments anticipated in the 2040s. These developments were identified with regards to the reference years used in the ISP to model varying weather patterns (for more detail see the *Alternative Weather Sequence* sensitivity, or the *ISP Methodology*[16]).

AEMO applied the reference year approach to ensure that real-world conditions that have been experienced were informing the future requirements. Given stakeholder concern regarding the predictability of weather within a 'rolling reference year' approach, AEMO applied two new considerations for the 2024 ISP modelling:

- To reflect that the timing and magnitude of low variable renewable energy (VRE) conditions is unknown, AEMO performed a sensitivity analysis to determine the resilience of the ODP to the lowest VRE yield reference year across the reference year collection across the outlook period, to assess capacity needs under more sustained poor renewable energy conditions (see Section A6.8.7).
- To reflect the uncertainty regarding the timing of poor weather conditions for renewable energy generation, AEMO introduced a constraint to progressively develop more firming resources as coal generation retires, to ensure that the system would be increasingly resilient before, during, and after poor weather conditions. This approach, applied to all scenarios, effectively resulted in the gradual development of more firming capacity than the Draft 2024 ISP forecast with perfect foresight of challenging weather conditions (See Appendix 2 for more details).

Reflecting detailed analysis of gas generation in the short to medium-term

AEMO has recognised that forecasting gas generation volumes – a technology that often and increasingly in the ISP is observed as a critical back-up to renewable energy and storage developments – benefits from high granularity modelling. AEMO has therefore calibrated the CBA with dispatch outcomes observed in its more granular time-sequential modelling for the period to 2030, being the period when most incumbent gas generation is operating before significant new flexible gas resources will be required to support coal closures.

[16] At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/isp-methodology-2023/isp-methodology_june-2023.pdf?la=en.

Reflecting the latest committed and anticipated projects as per the February 2024 Generation Information update

The February 2024 Generation Information update[17] includes around 3.7 gigawatts (GW) of new large-scale storage capacity as well as 490 megawatts (MW) of solar and wind, that have all now met 'anticipated' status, representing critical progress towards commencing operation in the NEM. Of these utility-scale storage capacities, approximately 3 GW in total is spread across Queensland, New South Wales, and Victoria.

As the project costs assumed in each scenario (including the counterfactual) are equivalent, these are ignored by the CBA when evaluating the ODP. While lowering the assessed system costs, the developments also have tended to reduce the relative market benefit of some transmission projects that provide significant generator and storage capital deferral benefits, as discussed in Section A6.6.2.

Inclusion of expanded renewable energy and emissions targets

The Capacity Investment Scheme's (CIS') Australia-wide targets of clean dispatchable and renewable capacity of 9 GW and 23 GW, respectively, and the additional Queensland and New South Wales emissions targets by 2035, have been incorporated in all scenarios. In particular, the clean dispatchable target will drive additional storage to be developed by 2030, while the renewable capacity target helps facilitate Australia's commitment to 82% renewable target by 2030. The 2024 ISP now includes a renewable energy development requirement that more closely follows the updated policy targets.

Updates to the distribution of demand across New South Wales sub-regions

Following the publication of the Draft 2024 ISP, AEMO has improved the distribution of electricity consumption across the NEM, particularly in New South Wales. The ISP model includes several sub-regions within New South Wales, and the updated allocations improves the sub-regional demand proportions relative to historically observed load distributions. The sub-regional demand proportions in New South Wales have been updated to represent proportions consistent with average load conditions[18] in the region (see Figure 5), resulting in greater load being represented in Southern New South Wales than was modelled in the Draft 2024 ISP.

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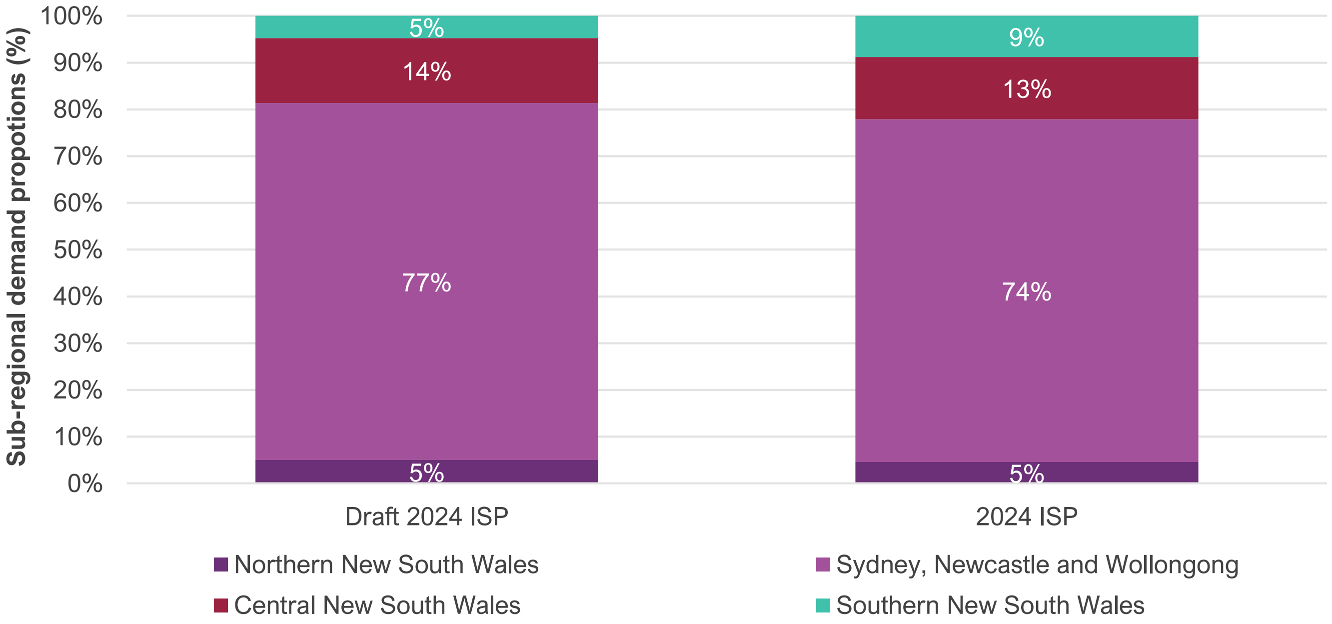
[17] At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

[18] The *Update to the 2023 Electricity Statement of Opportunities* (ESOO), published in May 2024, discusses a similar adjustment made to sub-regional demand proportions in New South Wales. However, the adjustments applied in the ESOO place more emphasis on periods of maximum demand when allocating demand, due to the greater focus on reliability during these periods in the ESOO, and as such will differ from those presented in this 2024 ISP, which are more representative of average load conditions.

Figure 5 Demand proportions applied in the 2024 ISP compared to the Draft 2024 ISP, (%)



Changes to the modelling of coordinated CER to improve the accounting of losses

AEMO has identified and corrected a modelling artefact that resulted in the double-counting of round-trip efficiency losses in the ISP modelling for coordinated CER batteries. Additionally, AEMO has applied greater operational limits on coordinated CER batteries to ensure only one full charging/discharging cycle is able to be deployed per day. This change improves the connection to observed operating behaviours, and improves the alignment to assumptions affecting CER batteries that are not assumed to be coordinated.

More information on how AEMO considers CER battery losses in demand forecasts is available in the *Electricity Demand Forecasting Methodology*[19].

Aligning hydrogen load forecast with proposed projects in *Green Energy Exports*

AEMO received feedback regarding the need for the *Green Energy Exports* scenario to reflect emerging industry in hydrogen related products, particularly green steel production, in locations most able to synergise with incumbent industry (and skilled workforce) and reflect related potential developments. AEMO accommodated this feedback in the *Green Energy Exports* scenario by attributing greater load for green steel furnaces and additional hydrogen load for green steel production into the Sydney, Newcastle, and Wollongong subregion – a location that hosts significant steelmaking capability.

Changes to transmission project assumptions

Continued joint planning with transmission network service providers (TNSPs) has identified improved information regarding several transmission projects modelled in the ISP. EISD and cost forecasts for several projects have

[19] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/forecasting-approach_electricity-demand-forecasting-methodology_final.pdf?la=en.

been revised, impacting their actionable windows compared to those applied in the Draft 2024 ISP. Changes to specific projects assessed for actionability are discussed in later sections of this Appendix, where relevant. Additionally,

- A number of committed and anticipated transmission projects have an updated timing or capacity, such as:
  - Far North Queensland Renewable Energy Zone (REZ) to be commissioned by 30 June 2024.
  - Central-West Orana REZ Network Infrastructure Project capacity full capacity release date is now scheduled for August 2028.
  - The two stages of full capacity releases for Project EnergyConnect are now scheduled for December 2024, and July 2027 respectively.
  - The South West Victoria (SWV1) group constraint has been revised to reflect the Mortlake turn-in project supporting 1,100 MW of transfer capacity (average additional generation output during peak summer periods), which was previously modelled as 1,500 MW (under optimal network conditions).
- Several new transmission augmentation options have been identified at smaller scale and cost than identified for the Draft 2024 ISP.
- Transmission limits and resource limits for some REZs have also been revised.

For more details, see Appendix 5 and the accompanying 2024 ISP Inputs and Assumptions Workbook[20].

Other relevant changes

The CDP collection has changed since the Draft 2024 ISP and now includes:

- Several additional REZ transmission augmentations (Waddamana to Palmerston transfer capability upgrade and Hunter-Central Coast REZ Network Infrastructure Project).
- Two additional projects that are now included within the CDP collection given updated modelling for the 2024 ISP, which were identified as potentially future projects only in the Draft 2024 ISP – Sydney Ring South and Mid North South Australia REZ Expansion.

The expanded project collection within the CDPs has necessitated changes to the CDP collection references from the Draft 2024 ISP. AEMO does not recommend comparing CDP identification labels (CDP-X) from the Draft 2024 ISP and the 2024 ISP, as the project list have changed.

This appendix focuses on the updated analysis in the 2024 ISP modelling, considering the changes laid out above. Comparisons against the Draft 2024 ISP findings are also presented where relevant.

Net impact of changes since the Draft 2024 ISP

The impacts of these changes vary across scenarios, CDPs and counterfactuals. Table 5 below shows the collective impacts on net market benefits across the scenarios, and the weighted net market benefits, including specific identification of the impact of emissions reduction benefits.

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

The inclusion of emissions reduction as a class of market benefits contributes approximately $3.3 billion to the overall weighted net market benefits. Emissions reduction benefits do not significantly impact the net market benefits in *Green Energy Exports* because of the rapid pace of decarbonisation in that scenario. Conversely, they have a more significant impact in *Progressive Change*, as the relatively slower decarbonisation allows for greater differences in fossil fuel generation across different development paths. In this scenario, early development of transmission unlocks high quality renewable resources which reduces fossil fuel generation – bringing forward emissions reduction and delivering economic benefits when valued using the VER.

Table 5 Comparison of the net market benefits of the ODP in the Draft 2024 ISP and in the 2024 ISP, and the contribution from emissions reduction benefits ($ billion)

	Step Change	*Progressive Change*	*Green Energy Exports*	Weighted net market benefits
Draft 2024 ISP	17.35	7.24	46.35	17.45
2024 ISP, net of emissions reduction benefits	16.54	5.88	59.57	18.52
Emissions reduction benefits	0.12	7.76	0.02	3.31
2024 ISP, with emissions reduction benefits	16.66	13.64	59.60	21.83

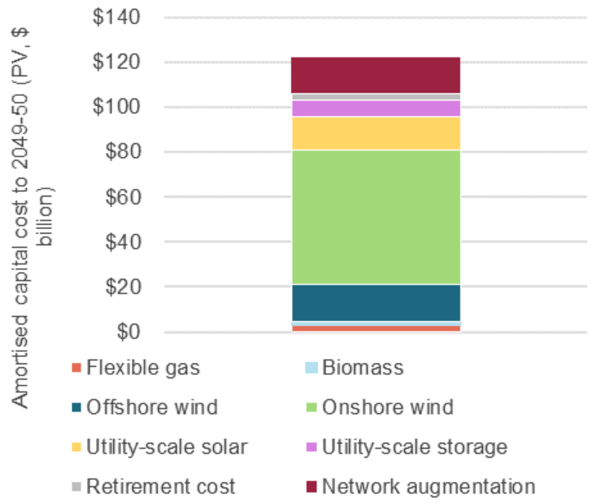
Note: The ODPs in the Draft 2024 ISP and the 2024 ISP differ in the set of actionable projects and their timings, therefore careful consideration must be observed when making comparisons. While this table compares the two different ODPs, ODP in the Draft 2024 ISP and the ODP in the 2024 ISP, both provide the optimal development paths under the set of assumption they were assessed against.

The annualised capital cost of all utility-scale generation, storage, firming and transmission infrastructure in the 2024 ISP's ODP has a present value of $122 billion in *Step Change* to 2050[21].

Of the annualised cost, transmission projects amount to $16 billion[22] or 13% of the total.

These investments deliver a net market benefit of almost $17 billion in *Step Change*, as shown in Table 5 above – that is, it provides a gross market benefit that exceeds the capital investment of $16 billion by almost $17 billion.

Figure 6 Present value of capital investments (amortised to 2049-50, $ billion)



[21] This value includes transmission augmentation, and utility-scale generation and storage capex, and does not include the cost of commissioned, committed or anticipated projects, consumer energy resources or distribution network upgrades. The value increased from $121 billion in the Draft 2024 ISP to $122 billion due to various modelling improvements as described in this report.

[22] This value is the net present value of capital costs for transmission augmentation up to 2049-50 only, and does not include the cost of commissioned, committed or anticipated projects.

A6.4 Step 1: Determining the least-cost development path for each scenario

The first stage in the CBA process was to determine the least-cost DP that maximises net market benefits under each scenario. The determination of the least-cost DP within each scenario was based on testing hundreds of permutations of network development options and timings. Each DP tested resulted in a different generation, storage, and transmission development schedule. The resulting NPVs of total system costs of all DPs were then compared to identify the DP that delivers the necessary infrastructure developments in the most economically efficient way by minimising the total system costs.

The process used to search for the least-cost DP in each scenario was as follows:

- The Single-Stage Long-Term[23] (SSLT) model was used to inform which transmission flow path augmentations are likely to minimise system costs, as well as an indication of the timing and scale of augmentation.
- Based on the indicative transmission developments provided by the SSLT modelling, many DPs were simulated in the Detailed Long Term (DLT) capacity outlook model to test which of the available network development options would produce the lowest total system costs, after accounting for the cost of the augmentations itself. For the augmentation to lower system costs, the savings from other costs must exceed the cost of the augmentation.
- These various augmentation options were then compared to a DP that does not have that option to identify a 'cross-over point' at which the project is starting to deliver positive net market benefits. Alternative timings were then tested around this 'cross-over point' to determine the optimal timing.
- This process was then repeated to include other ISP projects where there is a logical interaction to understand what combination of projects or project timings delivers the lowest system cost in each scenario.
- Additional augmentations were included to confirm that they do not provide incremental reductions in total system costs.

This section presents a concise summary of this process by detailing the least-cost DP for each scenario and comparing it to a subset of alternative DPs to illustrate the reasons for identifying a DP as optimal in a given scenario. This includes consideration of alternative projects or project options to demonstrate that these have been considered and why they were not optimal.

While many alternative DPs[24] were developed and analysed to explore a wide range of development possibilities across options and timings for each scenario, only a subset of the alternative DPs are presented in the tables below. These were hand-picked to demonstrate the merits of bigger, additional, or delayed augmentation options for a relevant transmission element in searching for the least-cost DP.

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[23] Further information on the differences between the Single-Stage Long-Term model and the Detailed Long-Term Model is provided in the *ISP Methodology*.

[24] DPs, as defined in the Glossary, are not scenario-specific, and can be explored in more than one scenario. DPs are not necessarily optimal in any scenario – generally, many DPs are tested to determine which DP is optimal in any given scenario.

This section highlights some of the alternative options assessed, focusing on some credible alternatives or further augmentations.

A6.4.1 Least-cost development path for *Step Change*

Table 6 presents the timings of relevant network development options in the least-cost DP for *Step Change* with a subset of relevant alternative DPs that were tested during the process of determining the least-cost DP.

The sample alternative DPs selected and contrasted below demonstrate:

- The reason for selecting Sydney Ring South Option 2d over Sydney Ring South Option 2b (Alternative DP1).
- The benefits provided by Queensland – New South Wales Interconnector (QNI) Connect Option 2 over the larger QNI Connect Option 5 (Alternative DP2).

Table 6 Subset of developments paths assessed in *Step Change*

Network option	Earliest in-service date (EISD)	Least-cost DP	Alternative DP1	Alternative DP2
Queensland SuperGrid North Option 1	**2030-31**	2044-45	2044-45	2044-45
Queensland SuperGrid North Option 2	**2032-33**			
Gladstone Grid Reinforcement	**2029-30**	2030-31	2030-31	2030-31
Queensland SuperGrid South Option 1	**2028-29**			
Queensland SuperGrid South Option 5	**2031-32**	2031-32	2031-32	2031-32
QNI Connect Option 2	**2033-34**	2034-35	2034-35	
QNI Connect Option 5	**2032-33**			2034-35
New England REZ Transmission Link 1	**2028-29**	2028-29	2028-29	2028-29
New England REZ Transmission Link 2	**2032-33**	2034-35	2034-35	2034-35
New England REZ Extension	**2028-29**	2030-31	2030-31	2030-31
Hunter-Central Coast REZ Network Infrastructure Project	**2029-30**	2030-31	2030-31	2030-31
Hunter Transmission Project	**2028-29**	2028-29	2028-29	2028-29
Sydney Ring South Option 2b	**2030-31**		2030-31	
Sydney Ring South Option 2d	**2028-29**	2029-30		2029-30
HumeLink	**2026-27**	2029-30	2029-30	2029-30
VNI West	**2029-30**	2029-30	2029-30	2029-30
Project Marinus Stage 1	**2030-31**	2030-31	2030-31	2030-31
Project Marinus Stage 2	**2032-33**	2048-49	2048-49	2048-49
Waddamana to Palmerston transfer capability upgrade	**2029-30**	2029-30	2029-30	2029-30
VIC-SESA Option 1	**2032-33**			
Mid North South Australia REZ Expansion	**2029-30**	2029-30	2029-30	2029-30
Reduction in net market benefits ($ million) compared with the least-cost DP		-	328	1,039

Note: Teal-coloured text highlights those projects that are delivered at their EISDs, and empty rows mean the corresponding projects are not delivered within the outlook period.

It is important to note that Hunter Transmission Project is an upgrade to the flow capacity to Sydney, Newcastle, and Wollongong subregion north of Sydney while Sydney Ring South Option 2b and Sydney Ring South Option 2d are upgrades to the flow capacity south of Sydney. Since the Draft 2024 ISP, further analysis of Sydney Ring South options have been conducted, and are presented here. The case for Hunter Transmission Project has not significantly changed since the Draft 2024 ISP and is presented in Section A6.6.2.

The following sections provide an overview of the comparisons between these DPs and the insights they provide on the optimal timing, costs, and benefits of a set of projects.

Benefits of developing Sydney Ring South

Alternative DP1 explores the potential benefits of developing Sydney Ring South Option 2b to support supply to the Sydney, Newcastle, and Wollongong subregion. This is instead of Sydney Ring Option 2d which is included in the least-cost DP for *Step Change*. Both the least-cost DP and Alternative DP1 develop the Sydney Ring South augmentation at their respective EISDs.

Sydney Ring South Option 2d, while not providing any additional transfer capacity to the CNSW-SNW flow path, improves power flow sharing between the northern and southern segments of the flow path and as a result allows greater generation transfer from Southern New South Wales into the Sydney, Newcastle and Wollongong subregion, at a cost of $235 million in 2029-30. In comparison, Sydney Ring South Option 2b provides an upgrade of 1,200 MW to the southern limit of the CNSW-SNW flow path, but with a later EISD of 2030-31 and higher cost at $975 million.

Table 7 shows the benefits of developing Sydney Ring South Option 2d at its EISD, one year earlier than Sydney Ring South Option 2b. While the larger Option 2b delivers modest savings in deferred generator and storage capital costs, these are outweighed by the higher augmentation cost. This means Sydney Ring South Option 2d is the preferred augmentation option in *Step Change*.

Table 7 Relative market benefits of the least-cost DP compared to Alternative DP1 (which has Sydney Ring South Option 2b instead), *Step Change*

Class of market benefits	Relative market benefits (NPV, $ million)
Generator and storage capital deferral	-35
Fixed operating and maintenance cost savings	-6
Fuel cost savings	-30
Variable operating and maintenance cost savings	-1
Voluntary and involuntary load shedding reductions	-5
Other network investment (REZ augmentations)	7
Gross market benefits excluding emissions	-71
Emissions reduction benefits	-10
Gross market benefits	-81
Network (Actionable and Future ISP Projects)	408
Total market benefits	328

Compared with Sydney Ring South Option 2d, development of Sydney Ring South Option 2b delivers relatively small generator and storage capital deferral benefits. The larger Sydney Ring South Option 2b also would enable greater flows from Southern New South Wales into the Sydney load centre along the southern segment of the CNSW-SNW flow path, which leads to fuel cost savings due to a reduction in GPG in the SNW subregion. These savings are relatively small in magnitude compared to the increase in cost of Sydney Ring South Option 2b however, hence the preference for Sydney Ring South Option 2d in the least-cost DP.

An assessment of the benefits that Sydney Ring South Option 2d provides on its own are explored in further detail in A6.6.2.

Benefits of developing QNI Connect options

The least-cost DP in *Step Change* sees the development of QNI Connect Option 2, which provides an increase to notional transfer capability of 1,260 MW from New South Wales to Queensland and 1,700 MW for flows in the reverse direction towards New South Wales with a cost of $2,764 million[25] in 2034-35. QNI Connect Option 2 helps support Queensland following a number of coal closures – in this scenario, all Queensland coal generators are forecast to be retired by 2034-35, driving its optimal timing in the least-cost DP.

While QNI Connect Option 2 is part of the least-cost DP, there is a limit on how efficient earlier expansion of the interconnection between New South Wales and Queensland is, as explored in Alternative DP2. In this alternative DP, the larger and more expensive QNI Connect Option 5, which has a notional transfer increase of 3,000 MW in the forward direction (from New South Wales to Queensland) and 2,250 MW in reverse direction and costs $5,750 million in 2034-35), is developed instead. Its northerly transfer capacity is almost double that of QNI Connect Option 2 while also providing over 500 MW of higher southerly transfer capacity.

Development of the larger option primarily results in fuel cost savings by reducing the utilisation of GPG in Queensland and New South Wales.

The larger QNI Connect Option 5 improves transfer capacity from northern New South Wales to south-west Queensland, however it is impacted by transmission bottlenecks between south-west Queensland and the south-east Queensland load centre. Full utilisation of the northerly transfer limit will at times be limited by this constraint, until additional upgrades to the south-west Queensland network are also developed by 2036-37 to accommodate increased flows into Queensland.

As Table 8 shows, the development of the smaller augmentation (QNI Connect Option 2) is forecast to provide a reduction in fuel cost savings amounting to $117 million, compensated by the smaller augmentation cost relative to the larger Option 5 ($1.2 billion in net present value). The net effect is that Option 2 results in an overall increase in relative benefits relative to Option 5.

As outlined in Appendix 2, the least-cost DP reflects the coal closure expectations outlined in the Queensland Energy and Jobs Plan and includes the development requirements of the Queensland Renewable Energy Target (QRET). While Borumba Dam Pumped Hydro is classified as an anticipated project, the Pioneer-Burdekin Pumped Hydro Project is not, and the least-cost DP does not develop quite the scale of deep-storage as is equivalent to

[25] As per AEMO's transmission cost escalation methods described in the 2023 *Transmission Expansion Options Report*, costs in this appendix have been escalated to the relevant year as required, compared to figures provided in Appendix 5.

this project to the same timeframe. Rather, there is increased use of southern renewable generation and firming capacity shared across the QNI Connect augmentation in the least-cost DP.

Table 8 Relative market benefits of least-cost DP compared with Alternative DP2 (which has a larger QNI Connect augmentation instead), *Step Change*

Class of market benefits	Relative market benefits (NPV, $ million)
Generator and storage capital deferral	0
Fixed operating and maintenance cost savings	-7
Fuel cost savings	-117
Variable operating and maintenance cost savings	-1
Voluntary and involuntary load shedding reductions	0
Other network investment (REZ augmentations)	16
Gross market benefits excluding emissions	-109
Emissions reduction benefits	-35
Gross market benefits	-145
Network (Actionable and Future ISP Projects)	1,184
Total market benefits	1,039

Benefits of the least-cost development path compared with the counterfactual DP

Table 9 provides a breakdown of the classes of market benefits delivered by the *Step Change's* least-cost DP compared with the counterfactual DP where no new major transmission is developed across the NEM[26]. Savings in generator capital costs and fuel costs from avoided development and operation of GPG in the absence of transmission augmentation represent the majority of the gross market benefits in *Step Change*.

[26] Neither flow path nor REZ transmission augmentations are allowed in this counterfactual. This does not include connecting assets for new plants which will continue to connect to the existing network.

Table 9 Net market benefits of the least-cost DP compared with the counterfactual DP (which has no transmission development), *Step Change*

Class of market benefits	Net market benefits (NPV, $ million)
Generator and storage capital deferral	13,638
Fixed operating and maintenance cost savings	-1,594
Fuel cost savings	19,900
Variable operating and maintenance cost savings	1,532
Voluntary and involuntary load shedding reductions	-225
Gross market benefits excluding emissions	33,251
Emissions reduction benefits	-37
Gross market benefits	33,214
Other network investment (REZ augmentations)	-1,677
Network (Actionable and Future ISP Projects)	-14,595
Total market benefits	16,942

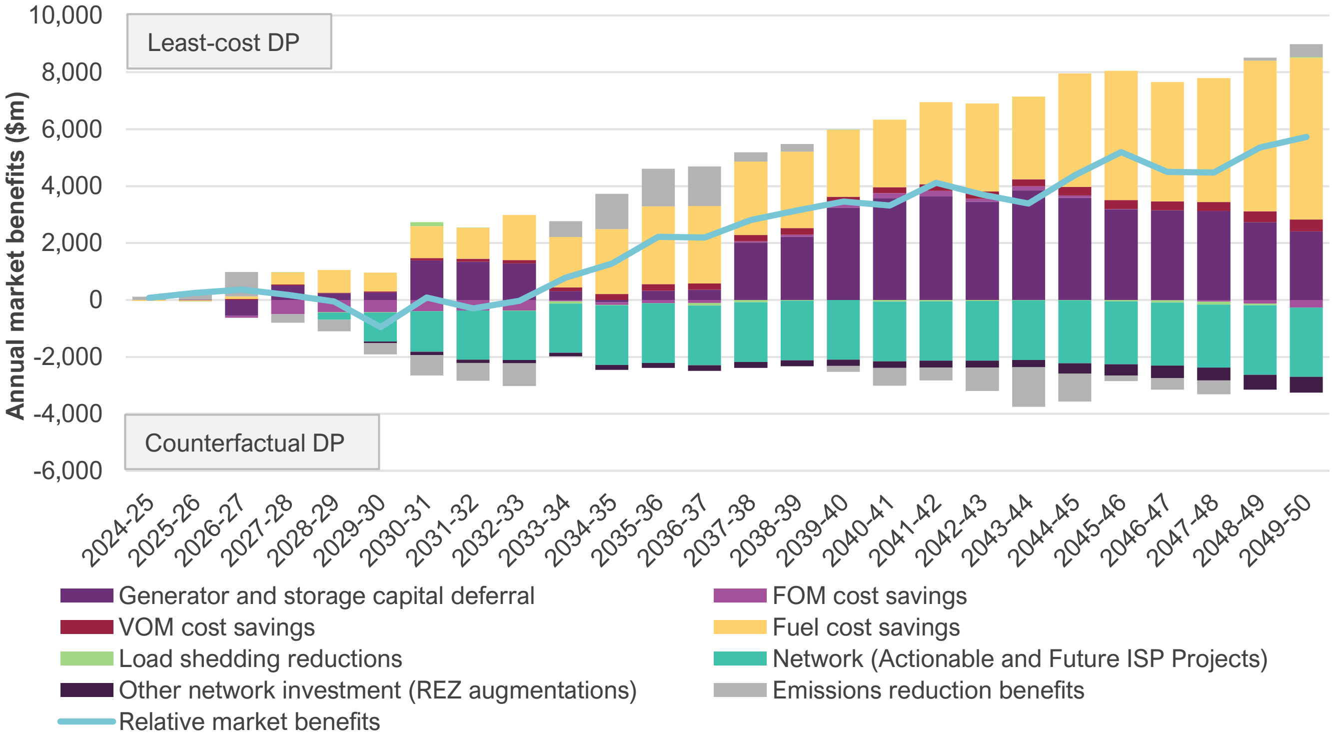
Figure 7 shows that the annual net market benefits of the least-cost DP in *Step Change* compared with the counterfactual DP (when actionable ISP projects are earliest to install) come primarily from avoided generator capital expenditure and fuel cost savings.

Without new transmission developments, additional capacity in renewable generation and firming capacity is needed earlier in the outlook period as coal retires and existing transmission limits the sharing of available capacity (as described in Section A2.3 of Appendix 2). Over the period to 2029-30, the counterfactual DP requires more gas and storage developments across most NEM regions to provide more firming resources, as well as more solar capacity to provide more energy production capability across the NEM.

The establishment of REZs will often require new transmission to strengthen the connection to the backbone network and to enable renewable generation connections at scale. As transmission is not developed in the counterfactual, some REZ developments will make way to increasingly more costly alternatives, including flexible gas with carbon-capture and storage to limit the scale of carbon emissions. Operating this flexible gas increases fuel costs and would likely require other developments in gas supply and mid-stream infrastructure which are only partially considered in this analysis, as well as carbon storage infrastructure. See Appendix 4 for insights on the capability of the gas system to supply the least-cost DP in *Step Change*.

Further comparisons of the capacity development and generation outcomes of the least-cost DP, and the *Step Change* scenario more broadly, are provided in Appendix 2.

Figure 7 Net market benefits of the least-cost DP relative to the counterfactual DP in *Step Change*



A6.4.2 Least-cost development path for *Progressive Change*

Table 10 presents the timings of the network development projects in the least-cost DP for *Progressive Change* and a subset of alternative DPs. The selection of alternative DPs shown below demonstrate:

- The relative market benefits of developing Project Marinus Stage 2 (Alternative DP3).
- Reasons for preference for Queensland SuperGrid South Option 5 over the smaller Queensland SuperGrid South Option 1 (Alternative DP4).

Table 10 Subset of developments paths assessed in *Progressive Change*

Network option	Earliest in-service date (EISD)	Least-cost DP	Alternative DP3	Alternative DP4
Queensland SuperGrid North Option 1	**2030-31**			
Queensland SuperGrid North Option 2	**2032-33**			
Gladstone Grid Reinforcement	**2029-30**	2034-35	2034-35	2034-35
Queensland SuperGrid South Option 1	**2028-29**			2034-35
Queensland SuperGrid South Option 5	**2031-32**	2034-35	2034-35	
QNI Connect Option 2	**2033-34**	2039-40	2039-40	2039-40
QNI Connect Option 5	**2032-33**			
New England REZ Transmission Link 1	**2028-29**	2029-30	2029-30	2029-30
New England REZ Transmission Link 2	**2032-33**	2041-42	2041-42	2041-42
New England REZ Extension	**2028-29**	2039-40	2039-40	2039-40

Network option	Earliest in-service date (EISD)	Least-cost DP	Alternative DP3	Alternative DP4
Hunter-Central Coast REZ Network Infrastructure Project	**2029-30**	2029-30	2029-30	2029-30
Hunter Transmission Project	**2028-29**	2030-31	2030-31	2030-31
Sydney Ring South Option 2b	**2030-31**			
Sydney Ring South Option 2d	**2028-29**	2038-39	2038-39	2038-39
HumeLink	**2026-27**	2030-31	2030-31	2030-31
VNI West	**2029-30**	2034-35	2034-35	2034-35
Project Marinus Stage 1	**2030-31**	2030-31	2030-31	2030-31
Project Marinus Stage 2	**2032-33**	2036-37		2036-37
Waddamana to Palmerston transfer capability upgrade	**2029-30**	2029-30	2029-30	2029-30
VIC-SESA Option 1	**2032-33**			
Mid North South Australia REZ Expansion	**2029-30**	2047-48	2047-48	2047-48
Reduction in net market benefits ($ million) compared with the least-cost DP		-	431	2,057

Note: Teal-coloured text highlights those projects that are delivered at their EISDs, and empty rows mean the corresponding projects are not delivered within the outlook period.

Benefits of developing Project Marinus Stage 2

Table 11 presents the relative market benefits of delivering Project Marinus Stage 2 by 2036-37 in *Progressive Change's* least-cost DP compared with Alternative DP3 which does not develop Project Marinus Stage 2 within the outlook period.

Project Marinus Stage 2 provides additional transfer capacity of 750 MW in both directions between Victoria and Tasmania at an estimated cost of $2,718 million in 2036-37[27].

By comparing the least-cost DP with Alternative DP3, the majority of the benefits that Project Marinus Stage 2 provides are identifiable, being primarily in generator and storage capacity deferral and fuel costs savings which amount to $432 million and $647 million respectively in NPV over the outlook period.

Table 11 Relative market benefits of developing Project Marinus Stage 2 towards the end of its actionable window compared to Alternative DP3, *Progressive Change*

Class of market benefits	Relative market benefits (NPV, $ million)
Generator and storage capital deferral	432
Fixed operating and maintenance cost savings	57
Fuel cost savings	647
Variable operating and maintenance cost savings	-18
Voluntary and involuntary load shedding reductions	28
Other network investment (REZ augmentations)	-7

[27] As per AEMO's transmission cost escalation methods described in the 2023 *Transmission Expansion Options Report*, costs in this appendix have been escalated to the relevant year as required, compared to figures provided in Appendix 5.

Class of market benefits	Relative market benefits (NPV, $ million)
Gross market benefits excluding emissions	1,139
Emissions reduction benefits	172
Gross market benefits	1,311
Network (Actionable and Future ISP Projects)	-880
Total market benefits	431

The development of Project Marinus Stage 2 in 2036-37 in the least-cost DP for *Progressive Change* increases the utilisation of renewable resources in Tasmania – including hydro generation from the existing hydro portfolio. Without the augmentation, greater use of GPG across the mainland NEM states is required. This results in fuel cost savings when Project Marinus Stage 2 is developed.

Project Marinus Stage 2 also enables the development of additional capacity in Tasmania's deep pumped hydro energy storages, avoiding the need for additional VRE, medium-depth storage and flexible gas capacity development on the mainland from the mid-2030s and providing capital deferral savings.

The project also enables reduced emissions, valued at $172 million in NPV. These differences in capacity expansion lead to benefits amounting to $431 million in NPV with Project Marinus Stage 2.

Benefits of developing Queensland SuperGrid South

Alternative DP4 highlights the relative market benefits of the larger Queensland SuperGrid South Option 5 over Queensland SuperGrid South Option 1. In the least-cost DP for *Progressive Change*, Queensland SuperGrid South Option 5 is developed in 2034-35 and in Alternative DP4, Queensland SuperGrid South Option 1 is developed in its place, at the same timing. Queensland SuperGrid South Option 5 provides 3,150 MW of additional transfer between Southern Queensland and Central Queensland in both directions with a cost of $3,481 million in 2034-35. Queensland SuperGrid South Option 1 is a much smaller capacity option, with less than a third of the transfer capacity (900 MW in both directions) and a cost of $871 million in 2034-35[28].

As Table 12 shows, greater benefits are accrued with the development of the larger Option 5, mainly coming from avoided generator and storage capital investments (estimated to be $1.9 billion in NPV terms) and from fuel cost savings and emissions reduction benefits of $608 million and $454 million respectively. Overall, the larger option results in higher net market benefits of $2.1 billion (after accounting for the higher cost of the augmentation). The augmentation increases access to the firming capacity provided by the anticipated Borumba Dam Pumped Hydro, as well as allowing greater energy and capacity sharing between South and Central Queensland.

Table 12 Relative market benefits of least-cost DP compared with Alternative DP4 (which has smaller Queensland SuperGrid South), *Progressive Change*

Class of market benefits	Relative market benefits (NPV, $ million)
Generator and storage capital deferral	1,872
Fixed operating and maintenance cost savings	132

[28] As per AEMO's transmission cost escalation methods described in the 2023 *Transmission Expansion Options Report*, costs in this appendix have been escalated to the relevant year as required, compared to figures provided in Appendix 5.

Class of market benefits	Relative market benefits (NPV, $ million)
Fuel cost savings	608
Variable operating and maintenance cost savings	35
Voluntary and involuntary load shedding reductions	23
Other network investment (REZ augmentations)	-27
Gross market benefits excluding emissions	2,644
Emissions reduction benefits	454
Gross market benefits	3,098
Network (Actionable and Future ISP Projects)	-1,040
Total market benefits	2,057

The improved access to the Borumba Dam Pumped Hydro and additional sharing capability between Southern and Central Queensland with the larger option (Queensland SuperGrid South Option 5) alleviates the need for firming investment in medium-depth and deep utility storage (1.4 GW across Queensland in 2034-35) and flexible gas capacity (300 MW in Southern Queensland in 2034-35). Additionally, the larger augmentation improves the utilisation of utility-scale solar in Queensland – mainly in the Wide Bay REZ.

Benefits of the least-cost development path compared with the counterfactual DP

Table 13 provides a breakdown of the classes of market benefits delivered by the least-cost DP in *Progressive Change* compared with the counterfactual DP[29]. Generator capital cost deferral, fuel cost savings, and emissions reduction benefits each represent roughly one third of the gross market benefits of the least-cost DP in *Progressive Change*.

Net market benefits have increased by approximately $6.8 billion from the Draft 2024 ISP, primarily from the inclusion of emissions reduction benefits.

Table 13 Net market benefits of the least-cost DP compared with the counterfactual DP (which has no transmission development), *Progressive Change*

Class of market benefits	Net market benefits (NPV, $ million)
Generator and storage capital deferral	8,817
Fixed operating and maintenance cost savings	1,056
Fuel cost savings	8,968
Variable operating and maintenance cost savings	278
Voluntary and involuntary load shedding reductions	-75
Gross market benefits excluding emissions	19,045
Emissions reduction benefits	8,196
Gross market benefits	27,240
Other network investment (REZ augmentations)	-735

[29] Neither flow path nor REZ transmission augmentations were allowed in this counterfactual. This does not include connecting assets for new plants which will continue to connect to the existing network.

Class of market benefits	Net market benefits (NPV, $ million)
Network (Actionable and Future ISP Projects)	-12,108
Total market benefits	14,398

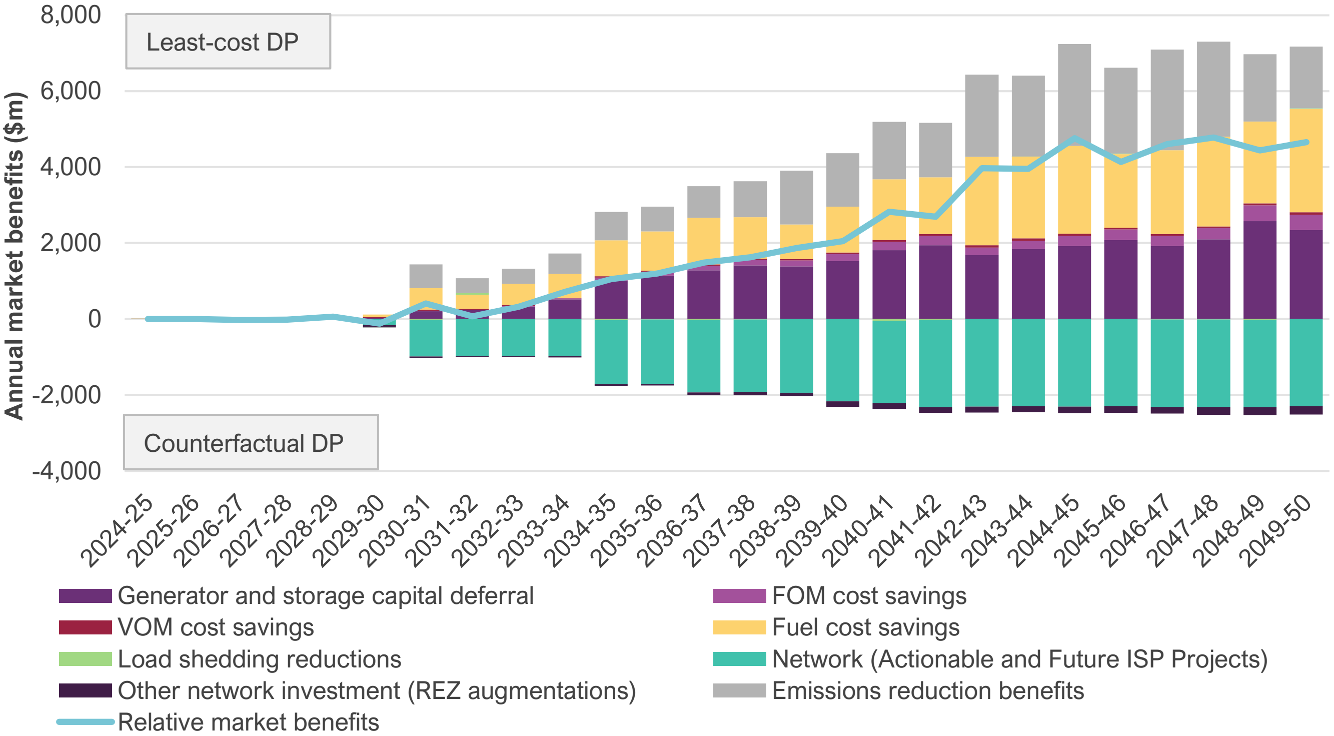
Emissions reduction benefits comprise a significant portion of the gross market benefits in *Progressive Change* compared to the other two scenarios. This is due to the more relaxed emissions budget in this scenario which leads to increased use of gas-powered generation in the counterfactual and a greater divergence of emissions pathways between CDPs.

Figure 8 shows that the annual net market benefits of the least-cost DP in *Progressive Change* start accruing from 2030-31 from fuel cost savings, emissions reduction benefits, and generator and storage capital deferral. While these benefits grow rapidly from 2035-36, the transmission development costs in the least-cost DP also increase.

Without transmission investment, the counterfactual DP relies on the development of GPG (around 1 GW from 2030-31 rising to 3.7 GW by 2041-42), medium and deep storages (at least 3.5 GW from 2034-35), and utility solar capacity. The increasing GPG capacity and utilisation results in greater fuel costs and higher emissions, which grow from the mid-2030s. Avoiding these fuel costs and reducing emissions represents the largest components of net benefit for the least-cost DP, avoiding high utilisation of GPG that is increasingly relied upon in the counterfactual DP due to the lack of network capacity to share resources across the NEM.

Appendix 2 provides further analysis of the differences in generation and storage development between the least-cost DP and counterfactual DP.

Figure 8 Net market benefits of the least-cost DP relative to the counterfactual DP in *Progressive Change*



A6.4.3 Least-cost development path for *Green Energy Exports*

Table 140 presents the timing of various transmission expansion options in the least-cost DP for *Green Energy Exports* and in a subset of alternative DPs. The *Green Energy Exports* scenario features relatively high economic growth and a strong commitment to decarbonise the economy, with the NEM providing a critical contribution.

The scenario therefore features the fastest rate of transformation, which in turn leads to greater need for the development of infrastructure. When contrasted with the least-cost DP, the alternative DPs selected demonstrate:

- How the Victoria to South East South Australia (VIC-SESA) augmentation (Option 1) does not deliver sufficient market benefits (Alternative DP5).
- The potential need for greater augmentation to the Sydney, Newcastle, and Wollongong subregion (Alternative DP6), given the higher growth forecast in the *Green Energy Exports* scenario.

The following sections provide an overview of the comparisons between these DPs and the insights they provide on the optimal timing, costs, and benefits of a selection of projects.

Table 14 Subset of developments paths assessed in *Green Energy Exports*

Network option	Earliest in-service date (EISD)	Least-cost DP	Alternative DP5	Alternative DP6
Queensland SuperGrid North Option 1	**2030-31**	2030-31	2030-31	2030-31
Queensland SuperGrid North Option 2	**2032-33**			
Gladstone Grid Reinforcement	**2029-30**	2030-31	2030-31	2030-31
Queensland SuperGrid South Option 1	**2028-29**	2028-29	2028-29	2028-29
Queensland SuperGrid South Option 5	**2031-32**	2032-33	2032-33	2032-33
QNI Connect Option 2	**2033-34**	2034-35	2034-35	2034-35
QNI Connect Option 5	**2032-33**			
New England REZ Transmission Link 1	**2028-29**	2028-29	2028-29	2028-29
New England REZ Transmission Link 2	**2032-33**	2034-35	2034-35	2034-35
New England REZ Extension	**2028-29**	2028-29	2028-29	2028-29
Hunter-Central Coast REZ Network Infrastructure Project	**2029-30**	2029-30	2029-30	2029-30
Hunter Transmission Project	**2028-29**	2028-29	2028-29	2028-29
Sydney Ring South Option 2b	**2030-31**	2039-40	2039-40	
Sydney Ring South Option 2d	**2028-29**	2028-29	2028-29	2028-29
HumeLink	**2026-27**	2029-30	2029-30	2029-30
VNI West	**2029-30**	2030-31	2030-31	2030-31
Project Marinus Stage 1	**2030-31**	2030-31	2030-31	2030-31
Project Marinus Stage 2	**2032-33**	2032-33	2032-33	2032-33
Waddamana to Palmerston transfer capability upgrade	**2029-30**	2029-30	2029-30	2029-30
VIC-SESA Option 1	**2032-33**		2032-33	
Mid North South Australia REZ Expansion	**2029-30**	2029-30	2029-30	2029-30
Reduction in net market benefits ($ million) compared with the least-cost DP		-	446	732

Note: Teal-coloured text highlights those projects that are delivered at their EISDs, and empty rows mean the corresponding projects are not delivered within the outlook period.

Benefits of developing VIC-SESA Option 1

Alternative DP5 explores whether an augmentation of the VIC-SESA flow path would deliver net market benefits in *Green Energy Exports* given the scale of transformation required across all regions to meet domestic demand as well as emerging demand for green energy industries in this scenario.

VIC-SESA Option 1 provides an additional 1,640 MW of transmission capacity between Victoria and South Australia in both directions, which allows for higher levels of REZ development in South Australian REZs. This augmentation option costs $973 million in 2032-33[30].

[30] As per AEMO's transmission cost escalation methods described in the 2023 *Transmission Expansion Options Report*, costs in this appendix have been escalated to the relevant year as required, compared to figures provided in Appendix 5.

Table 15 shows the benefits of developing the VIC-SESA Option 1 augmentation in 2032-33 (Alternative DP5), compared with the least-cost DP for *Green Energy Exports* which does not include it throughout the outlook period. Alternative DP5 demonstrates that the augmentation would deliver only a relatively small cost reduction despite it providing greater REZ access and transfer capacity between regions. Only approximately 80 MW of additional wind capacity is developed in South East South Australia by 2040-41 under Alternative DP5 compared with the least-cost DP, and most of the energy produced from that new VRE capacity is transferred to Victoria due to the relatively minimal demand in South East South Australia. Despite the additional network capacity, there is little development of VRE in South East South Australia as developments in Victorian offshore wind capacity (driven by government policy) limits the utilisation and therefore value of the VRE connectivity improvement, which reduces relative market benefits by $446 million in this scenario.

Table 15 Relative market benefits of the least-cost DP compared to Alternative DP5 (which includes VIC-SESA Option 1), *Green Energy Exports*

Class of market benefits	Relative market benefits (NPV, $ million)
Generator and storage capital deferral	-48
Fixed operating and maintenance cost savings	8
Fuel cost savings	4
Variable operating and maintenance cost savings	-1
Voluntary and involuntary load shedding reductions	-8
Other network investment (REZ augmentations)	24
Gross market benefits excluding emissions	-21
Emissions reduction benefits	-0
Gross market benefits	-21
Network (Actionable and Future ISP Projects)	468
Total market benefits	446

Benefits of additional augmentation to Sydney, Newcastle, and Wollongong

The least-cost DP for *Green Energy Exports* develops multiple Sydney Ring South augmentations to provide adequate supply to the Sydney, Newcastle, and Wollongong subregion as demand increases throughout the outlook period. Hunter Transmission Project (which is an upgrade to the flow capacity on the north side of Sydney, Newcastle, and Wollongong subregion) and Sydney Ring South Option 2d (which is an upgrade to the flow capacity on the south side of Sydney, Newcastle, and Wollongong subregion) are both initially developed at their EISDs of 2028-29, while Sydney Ring Option South 2b is developed as a subsequent upgrade in 2040-41, providing an additional increase of 1,200 MW in transmission capacity with a cost of $1,026 million[31].

Alternative DP6 evaluates the impact on total system costs of not developing Sydney Ring South Option 2b, which is developed in the least-cost DP for *Green Energy Exports* at 2040-41. All other augmentations are developed at the same timings as those for the least-cost DP. The relative market benefits between these two DPs are

[31] As per AEMO's transmission cost escalation methods described in the 2023 *Transmission Expansion Options Report*, costs in this appendix have been escalated to the relevant year as required, compared to figures provided in Appendix 5.

presented in Table 16, demonstrating that developing this expanded Sydney Ring South augmentation as a future project results in an overall increase in relative market benefits of $732 million.

The main driver of these benefits is to avoid the need for utility storage investment (1.5 GW by 2044-45) across New South Wales, as well additional solar capacity across the NEM by 2049-50. The augmentation strengthens the peak supply capability to the major load centre, reducing the potential need for DSP utilisation throughout the 2040s as well and delivering a further $152 million in benefits.

Table 16 Relative market benefits of the least-cost DP compared to Alternative DP6 (which does not include Sydney Ring South Option 2b), *Green Energy Exports*

Class of market benefits	Relative market benefits (NPV, $ million)
Generator and storage capital deferral	619
Fixed operating and maintenance cost savings	201
Fuel cost savings	14
Variable operating and maintenance cost savings	-3
Voluntary and involuntary load shedding reductions	152
Other network investment (REZ augmentations)	-13
Gross market benefits excluding emissions	970
Emissions reduction benefits	1
Gross market benefits	971
Network (Actionable and Future ISP Projects)	-238
Total market benefits	732

Benefits of the least-cost development path compared with the counterfactual DP

While the counterfactual DP typically does not allow for major transmission augmentation developments beyond those projects that are already committed and anticipated, the ability to develop sufficient renewable generation to be internally consistent with the scenario definition will require some capacity to increase the network to REZs. Without this, the scenario would rely upon carbon sequestration to provide an ‘almost green’ source of energy, which would amplify the potential system costs beyond that which is considered reasonable for the purposes of the cost-benefit analysis.

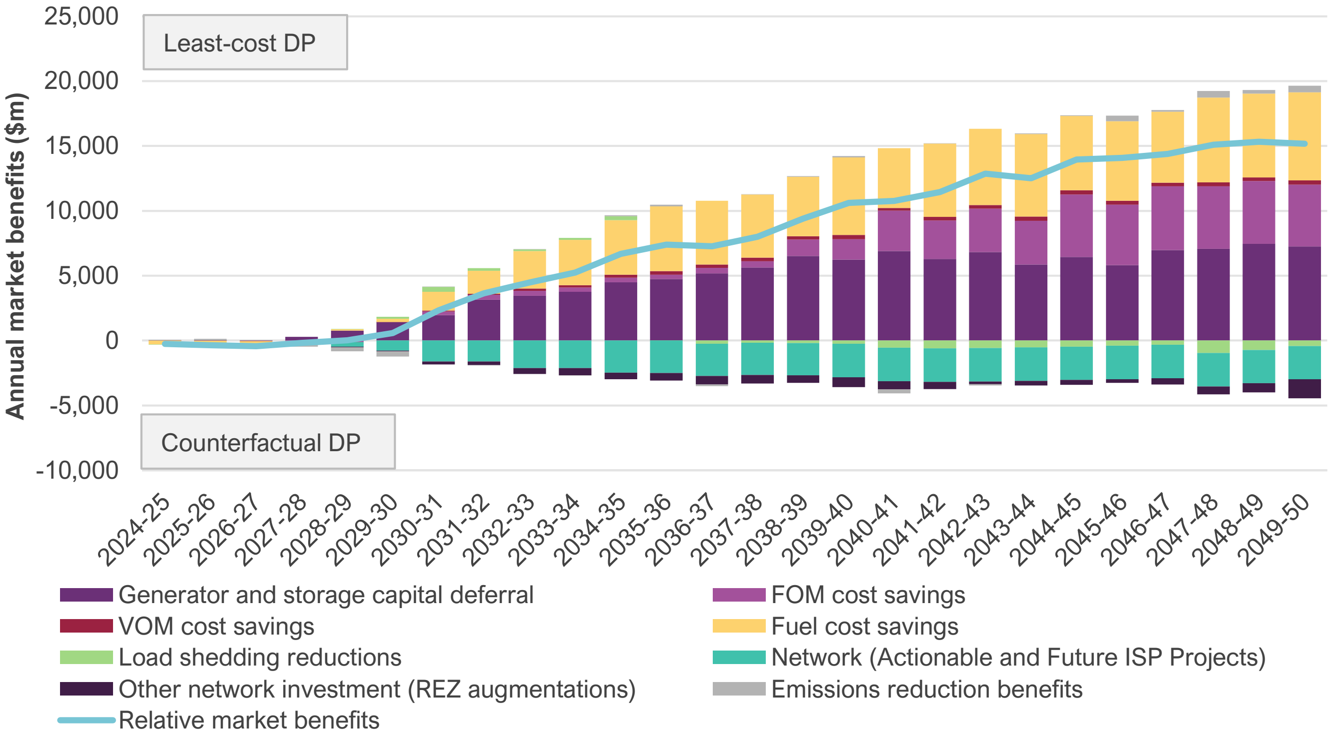
Table 170 provides a breakdown of the classes of market benefits delivered by the least-cost DP compared with the counterfactual DP in *Green Energy Exports*. This shows that avoided generator capital costs and avoided fuel costs represent most of the gross market benefits in *Green Energy Exports*.

Table 17 Net market benefits of the least-cost DP compared with the counterfactual DP (which has no transmission development), *Green Energy Exports*

Class of market benefits	Net market benefits (NPV, $ million)
Generator and storage capital deferral	37,328
Fixed operating and maintenance cost savings	12,616
Fuel cost savings	30,336
Variable operating and maintenance cost savings	1,541
Voluntary and involuntary load shedding reductions	-1,287
Gross market benefits excluding emissions	80,534
Emissions reduction benefits	24
Gross market benefits	80,558
Other network investment (REZ augmentations)	-3,986
Network (Actionable and Future ISP Projects)	-16,746
Total market benefits	59,826

Figure 9 presents the annual net market benefits of the least-cost DP in *Green Energy Exports*. Benefits begin to accrue relatively quickly, as transmission assets are developed from 2027-28, reducing the need for alternative generator capital investment. Without transmission investment, the cost of operating the NEM with such a limited carbon budget is also greater, given the reduced total capability to develop renewable energy in REZs, and to compensate for this the counterfactual DP brings forward coal retirements (and the cost of these closures).

Figure 9 Net market benefits of the least-cost DP relative to the counterfactual DP in *Green Energy Exports*



To continue to supply a growing NEM with limited renewable generation options, the counterfactual DP starts to invest in flexible gas with carbon capture and storage (CCS) from 2030-31[32]. This increases capital costs and fuel costs in the counterfactual DP. Some additional utility-scale storage is also required, and greater utilisation of offshore wind (beyond the Victorian Offshore Wind Target).

Further comparisons of the capacity development and generation outcomes are provided in Section A2.3 of Appendix 2.

A6.4.4 Comparing the least-cost development paths

The majority of the ISP projects considered in the least-cost DPs of each scenario deliver net market benefits in all scenarios. However, their optimal timings differ in ways that are generally proportional to the speed of emissions reduction, coal retirements, and energy consumption forecast within each scenario. For example, in *Green Energy Exports* the pace of transition of the NEM provides increased need for additional projects to be developed at their EISDs (approximately) to supply load growth, REZ expansions, and to support the operation of electrolyser facilities to provide broader green energy opportunities.

Excluding the additional benefits attributable to emissions reduction, the net market benefits in each scenario are lower than those assessed in the 2022 ISP, especially in *Green Energy Exports* when compared with *Hydrogen Superpower* from the 2022 ISP. This is primarily due to:

- Increased transmission costs, which in this 2024 ISP are assumed to increase over the outlook period in real terms.
- Increased capital costs for new VRE generators and storage technologies, offset by a relatively small increase in capital costs for GPG.
- Additional committed and anticipated transmission projects since the 2022 ISP, such as CopperString 2032, Western Renewables Link (uprate), and Mortlake Turn-In all provide additional REZ hosting capacity under all DPs to allow more VRE development before transmission augmentation is required.
- Federal and state policies have provided greater stimuli for VRE and storage build-out in the 2024 ISP in all scenarios, reducing the gap in generation development with each scenario's counterfactual DP.
- Lower gas prices in the 2024 ISP, meaning that the counterfactual DPs (that rely more on GPG rather than capacity sharing between regions) is relatively lower cost to operate GPG.

Since the Draft 2024 ISP, further changes to inputs and assumptions have influenced the resulting net market benefits. These are discussed in more detail in Section A6.3, and include:

- Inclusion of emissions reduction as a class of benefits, which is most impactful in *Progressive Change* due to the higher emissions budget.
- Considerations of limitations in existing gas infrastructure, impacting the costs associated with high levels of GPG operation.

[32] This counterfactual DP does not apply a supply chain limit on the availability of carbon capture and storage infrastructure; if CCS facilities were unavailable by this time, then other options to reduce emissions may be required.

- Aligning existing GPG production in short- to medium-term operation with current and recent historical performance.
- Addition of newly committed and anticipated generation and storage projects as per the February 2024 Generation Information update, as well as changes to the capacities and target commercial use dates for several projects already included in the Draft 2024 ISP.
- Inclusion of the expanded CIS targets for clean dispatchable and renewable capacity of 9 GW and 23 GW respectively, Australia-wide.
- Changes to several transmission-related inputs, including the EISDs and costs of augmentation options, capacity and timing of committed and anticipated transmission projects, and existing transmission and resource limits.

As further detailed in Appendix 5, in *Step Change* approximately 5,000 km of transmission is needed in the next decade, about half of which is already underway as committed or anticipated projects. Under the *Step Change* scenario, around 8,000 km of transmission is needed by 2050. *Progressive Change* follows a similar but slightly delayed and lower trajectory, with no significant projects from the early 2040s. The pace of demand growth and the greater need to reduce emissions in *Green Energy Export* results in more and earlier builds compared to the other scenarios, with almost 25,000 kilometres of new transmission network investments by 2049-50.

Table 18 Comparing the least-cost DPs between scenarios

Network option	Earliest in-service date (EISD)	*Step Change*	*Progressive Change*	*Green Energy Exports*
Queensland SuperGrid North Option 1	**2030-31**	2044-45		2030-31
Gladstone Grid Reinforcement	**2029-30**	2030-31	2034-35	2030-31
Queensland SuperGrid South Option 1	**2028-29**			2028-29
Queensland SuperGrid South Option 5	**2031-32**	2031-32	2034-35	2032-33
QNI Connect Option 2	**2033-34**	2034-35	2039-40	2034-35
New England REZ Transmission Link 1	**2028-29**	2028-29	2029-30	2028-29
New England REZ Transmission Link 2	**2032-33**	2034-35	2041-42	2034-35
New England REZ Extension	**2028-29**	2030-31	2039-40	2028-29
Hunter-Central Coast REZ Network Infrastructure Project	**2029-30**	2030-31	2029-30	2029-30
Hunter Transmission Project	**2028-29**	2028-29	2030-31	2028-29
Sydney Ring South Option 2b	**2030-31**			2039-40
Sydney Ring South Option 2d	**2028-29**	2029-30	2038-39	2028-29
HumeLink	**2026-27**	2029-30	2030-31	2029-30
VNI West	**2029-30**	2029-30	2034-35	2030-31
Project Marinus Stage 1	**2030-31**	2030-31	2030-31	2030-31
Project Marinus Stage 2	**2032-33**	2048-49	2036-37	2032-33
Waddamana to Palmerston transfer capability upgrade	**2029-30**	2029-30	2029-30	2029-30
Mid North South Australia REZ Expansion	**2029-30**	2029-30	2047-48	2029-30

Note: Teal-coloured text highlights those projects that are delivered at their EISDs.

A6.4.5 Identifying potential actionable and future ISP projects

Projects in each least-cost DP are considered to be potential actionable projects if their optimal timing is found within their actionable windows. The subset of potential actionable projects forms the basis of the CDPs to be assessed in the next stage of the CBA.

Table 19 presents the projects identified as being potentially actionable in at least one scenario, their EISD and their actionable window. In all tables in this document, the actionable window is always inclusive of the EISD.

Since the Draft 2024 ISP, two new projects have been identified as potentially actionable in at least one scenario: Hunter-Central Coast REZ Network Infrastructure Project and Sydney Ring South Option 2d. These projects are now tested via CDPs and are discussed in further detail in Section A6.6.2.

Table 19 Potential actionable projects in the *2024 ISP*

Network option	Potentially actionable in…	EISD or first year of actionable window	Length of actionable window (years)[A]	Last year of actionable window
Queensland SuperGrid North Option 1	*Green Energy Exports*	2030-31	2	2031-32
Gladstone Grid Reinforcement	*Step Change, Green Energy Exports*	2029-30	2	2030-31
Queensland SuperGrid South Option 1	*Green Energy Exports*	2028-29	2	2029-30
Queensland SuperGrid South Option 5	*Step Change, Green Energy Exports*	2031-32	2	2032-33
QNI Connect Option 2	*Step Change, Green Energy Exports*	2033-34	2	2034-35
New England REZ Transmission Link 1	All scenarios	2028-29	4	2031-32
New England REZ Extension	*Step Change, Green Energy Exports*	2028-29	4	2031-32
Hunter-Central Coast REZ Network Infrastructure Project	All scenarios	2029-30	2	2030-31
Hunter Transmission Project	All scenarios	2028-29	4	2031-32
Sydney Ring South Option 2d	*Step Change, Green Energy Exports*	2028-29	2	2029-30
HumeLink	All scenarios	2026-27	6	2031-32
VNI West	All scenarios	2029-30	6	2034-35
Project Marinus Stage 1	All scenarios	2030-31	6	2035-36
Project Marinus Stage 2	*Progressive Change, Green Energy Exports*	2032-33	6	2037-38
Waddamana to Palmerston transfer capability upgrade	All scenarios	2029-30	2	2030-31
Mid North South Australia REZ Expansion	*Step Change, Green Energy Exports*	2029-30	2	2030-31

A. Actionable window is always inclusive of the EISD.

See Appendix 5 for more information on network investments.

A6.5 Step 2: Determining the set of candidate development paths to identify the ODP

A CDP represents a collection of DPs which share a set of potentially actionable projects. CDPs vary with respect to status of the potentially actionable projects.

The least-cost DP in each scenario were used as a basis for forming the initial set of CDPs. Additional CDPs are added based on the process set out in Section 5.4 of the *ISP Methodology*, which involves forming new CDPs by moving the timings of potentially actionable projects in an existing CDP or by including additional or alternative projects to a CDP.

The CDPs examined in this 2024 ISP are shown in Table 20, which also sets out how each CDP is developed. CDPs have been designed to primarily explore the set of projects that are identified as potentially actionable in *Progressive Change and Step Change*, as well as a subset of projects identified as potentially actionable in *Green Energy Exports* that demonstrate relative early development timing in the other scenarios. The purpose of each CDP will be further explained in Section A6.6.

Note that these CDPs are not comparable to the CDP labels used in the Draft 2024 ISP as there are several additional potential actionable projects being assessed in the 2024 ISP, hence the numbering of the CDPs has subsequently changed. Care must be taken if seeking to compare CDP outcomes from the Draft 2024 ISP to this 2024 ISP.

The first three CDPs are based on the least-cost DP from each scenario:

- CDP1, which is based on *Green Energy Exports'* least-cost DP as defined in Table 18.
- CDP2, which is based on *Progressive Change*'s least-cost DP as defined in Table 18.
- CDP3, which is based on *Step Change's* least-cost DP as defined in Table 18.

To test earlier timing of investments, the following CDPs were created:

- CDP10, which moves New England REZ Transmission Link 2 to within its actionable window in contrast with CDP3.
- CDP14, which moves Project Marinus Stage 2 to within its actionable window in contrast with CDP3, given the project is developed within its actionable window in CDP1 and CDP2.
- CDP17, which moves Queensland SuperGrid North to within its actionable window in contrast with CDP3, given the project is developed within its actionable window in CDP1.

To explore later timing of investments:

- CDP4, which moves Hunter Transmission Project to outside its actionable window in contrast with CDP3.
- CDP5, which moves Sydney Ring South to outside its actionable windows in contrast with CDP3.
- CDP6, which moves Hunter Transmission Project and Sydney Ring South to outside their actionable windows in contrast with CDP3.
- CDP7, which moves HumeLink to outside its actionable window in contrast with CDP3.

- CDP8, which moves VNI West to outside its actionable window in contrast with CDP3.
- CDP9, which moves New England REZ Transmission Link 1 and the New England REZ Extension to outside their actionable windows in contrast with CDP3.
- CDP11, which moves the New England REZ Extension to outside its actionable window in contrast with CDP3.
- CDP12, which moves the Hunter-Central Coast REZ Network Infrastructure Project to outside its actionable window in contrast with CDP3.
- CDP13, which moves Project Marinus Stage 1 to outside its actionable window in contrast with CDP3.
- CDP15, which moves the Waddamana to Palmerston transfer capability upgrade to outside its actionable window in contrast with CDP3.
- CDP16, which moves Mid North South Australia REZ Expansion to outside its actionable window in contrast with CDP3.
- CDP18, which moves Queensland SuperGrid South to outside its actionable window in contrast with CDP3.
- CDP19, which moves Queensland SuperGrid South and Gladstone Grid Reinforcement to outside their actionable windows in contrast with CDP3. As Gladstone Grid is a pre-requisite to Queensland SuperGrid South Option 5, both are delayed beyond the actionable window.
- CDP20, which moves Queensland SuperGrid South and Sydney Ring South to outside their actionable windows in contrast with CDP3.
- CDP22, which moves QNI Connect to outside its actionable window in contrast with CDP3.
- CDP25, which delays all projects to outside their actionable windows.

Finally, to test alternative combinations of investments through both earlier and later timing of projects, the following CDPs were created:

- CDP21, which moves Project Marinus Stage 2 to within its actionable window but Sydney Ring South to outside its actionable window in contrast with CDP3.
- CDP23, which moves Project Marinus Stage 2 to within its actionable window but QNI Connect to outside its actionable window in contrast with CDP3.
- CDP24, which moves Project Marinus Stage 2 to within its actionable window but Queensland SuperGrid South to outside its actionable window in contrast with CDP3.

Table 20 Candidate development paths

In these CDPs…		**… these projects would be actionable**															
CDP	**Description**	**Queensland SuperGrid North**	**Gladstone Grid Reinforcement**	**Queensland SuperGrid South**	**QNI Connect**	**New England REZ Transmission Link 1**	**New England REZ Transmission Link 2**	**New England REZ Extension**	**Hunter-Central Coast REZ Network Infrastructure Project**	**Hunter Transmission Project**	**Sydney Ring South**	**HumeLink**	**VNI West**	**Project Marinus Stage 1**	**Project Marinus Stage 2**	**Waddamana to Palmerston transfer capability upgrade**	**Mid North South Australia REZ Expansion**
Least-cost DPs in each scenario																	
1	Least cost DP for *Green Energy Exports*	✓	✓	✓	✓	✓		✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
2	Least cost DP for *Progressive Change*					✓			✓	✓		✓	✓	✓	✓	✓	
3	Least cost DP for *Step Change*		✓	✓	✓	✓		✓	✓	✓	✓	✓	✓	✓		✓	✓
Testing alternative timings based on CDP3																	
4	CDP3 without actionable Hunter Transmission Project		✓	✓	✓	✓		✓	✓		✓	✓	✓	✓		✓	✓
5	CDP3 without actionable Sydney Ring South		✓	✓	✓	✓		✓	✓	✓		✓	✓	✓		✓	✓
6	CDP3 without actionable Hunter Transmission Project nor Sydney Ring South		✓	✓	✓	✓		✓	✓			✓	✓	✓		✓	✓
7	CDP3 without actionable HumeLink		✓	✓	✓	✓		✓	✓	✓	✓		✓	✓		✓	✓
8	CDP3 without actionable VNI West		✓	✓	✓	✓		✓	✓	✓	✓	✓		✓		✓	✓
9	CDP3 without actionable New England REZ Transmission Link 1 nor New England REZ Extension		✓	✓	✓				✓	✓	✓	✓	✓	✓		✓	✓
10	CDP3 with actionable New England REZ Transmission Link 2		✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓	✓
11	CDP3 without actionable New England REZ Extension		✓	✓	✓	✓			✓	✓	✓	✓	✓	✓		✓	✓

In these CDPs…		… these projects would be actionable															
CDP	**Description**	**Queensland SuperGrid North**	**Gladstone Grid Reinforcement**	**Queensland SuperGrid South**	**QNI Connect**	**New England REZ Transmission Link 1**	**New England REZ Transmission Link 2**	**New England REZ Extension**	**Hunter-Central Coast REZ Network Infrastructure Project**	**Hunter Transmission Project**	**Sydney Ring South**	**HumeLink**	**VNI West**	**Project Marinus Stage 1**	**Project Marinus Stage 2**	**Waddamana to Palmerston transfer capability upgrade**	**Mid North South Australia REZ Expansion**
12	CDP3 without actionable Hunter-Central Coast REZ Network Infrastructure Project		✓	✓	✓	✓		✓		✓	✓	✓	✓	✓		✓	✓
13	CDP3 without actionable Project Marinus Stage 1		✓	✓	✓	✓		✓	✓	✓	✓	✓	✓			✓	✓
14	CDP3 with actionable Project Marinus Stage 2		✓	✓	✓	✓		✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
15	CDP3 without actionable Waddamana to Palmerston transfer capability upgrade		✓	✓	✓	✓		✓	✓	✓	✓	✓	✓	✓			✓
16	CDP3 without actionable Mid North South Australia REZ Expansion		✓	✓	✓	✓		✓	✓	✓	✓	✓	✓	✓		✓	
17	CDP3 with actionable Queensland SuperGrid North	✓	✓	✓	✓	✓		✓	✓	✓	✓	✓	✓	✓		✓	✓
18	CDP3 without actionable Queensland SuperGrid South		✓		✓	✓		✓	✓	✓	✓	✓	✓	✓		✓	✓
19	CDP3 without actionable Queensland SuperGrid South nor Gladstone Grid Reinforcement				✓	✓		✓	✓	✓	✓	✓	✓	✓		✓	✓
20	CDP3 without actionable Queensland SuperGrid South nor actionable Sydney Ring South		✓		✓	✓		✓	✓	✓		✓	✓	✓		✓	✓
21	CDP3 with actionable Project Marinus Stage 2 but without actionable Sydney Ring South		✓	✓	✓	✓		✓	✓	✓		✓	✓	✓	✓	✓	✓
22	CDP3 without actionable QNI Connect		✓	✓		✓		✓	✓	✓	✓	✓	✓	✓		✓	✓
23	CDP3 with actionable Project Marinus Stage 2 but without actionable QNI Connect		✓	✓		✓		✓	✓	✓	✓	✓	✓	✓	✓	✓	✓

In these CDPs…		… these projects would be actionable															
CDP	**Description**	**Queensland SuperGrid North**	**Gladstone Grid Reinforcement**	**Queensland SuperGrid South**	**QNI Connect**	**New England REZ Transmission Link 1**	**New England REZ Transmission Link 2**	**New England REZ Extension**	**Hunter-Central Coast REZ Network Infrastructure Project**	**Hunter Transmission Project**	**Sydney Ring South**	**HumeLink**	**VNI West**	**Project Marinus Stage 1**	**Project Marinus Stage 2**	**Waddamana to Palmerston transfer capability upgrade**	**Mid North South Australia REZ Expansion**
24	CDP3 with actionable Project Marinus Stage 2 but without actionable Queensland SuperGrid South		✓		✓	✓		✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Testing a CDP with no actionable projects																	
25	No actionable projects																

Note: Teal-coloured cells with ticks highlight the actionable projects in each CDP.

Table 21 shows similar information in a different view.

Table 21 Candidate development paths

Least-cost DP for each scenario[A]		
CDP1	All projects actionable in *Green Energy Exports*	
CDP2	All projects actionable in *Progressive Change*	
CDP3	All projects actionable in *Step Change*	
New CDP	**Projects brought forward to within their actionable windows relative to CDP3**	**Projects pushed back beyond their actionable windows relative to CDP3**
CDP4		Hunter Transmission Project
CDP5		Sydney Ring South
CDP6		Hunter Transmission Project and Sydney Ring South
CDP7		HumeLink
CDP8		VNI West
CDP9		New England REZ Transmission Link 1 and New England REZ Extension
CDP10	New England REZ Transmission Link 2	
CDP11		New England REZ Extension
CDP12		Hunter-Central Coast REZ Network Infrastructure Project
CDP13		Project Marinus Stage 1
CDP14	Project Marinus Stage 2	
CDP15		Waddamana to Palmerston transfer capability upgrade
CDP16		Mid North South Australia REZ Expansion
CDP17	Queensland SuperGrid North	
CDP18		Queensland SuperGrid South
CDP19		Queensland SuperGrid South and Gladstone Grid Reinforcement
CDP20		Queensland SuperGrid South and Sydney Ring South
CDP21	Project Marinus Stage 2	Sydney Ring South
CDP22		QNI Connect
CDP23	Project Marinus Stage 2	QNI Connect
CDP24	Project Marinus Stage 2	Queensland SuperGrid South
CDP25		No actionable projects (all delayed to outside their actionable windows)

A. See Table 20 above.

A6.6 Steps 3 to 5: Assessing the candidate development paths

A6.6.1 Ranking the Candidate Development Paths

The identification of the ODP is informed by assessing the performance of the CDPs across each of the scenarios, as well as their resilience across the sensitivities implemented (see Section A6.8). This section compares the various CDPs to explore the costs and benefits provided by potential actionable projects, including their impact on each other.

The *ISP Methodology* outlined two approaches that are used to rank the CDPs:

- **Approach A** – a scenario-weighted approach to averaging the net market benefits of each CDP across all scenarios. CDPs are ranked in descending order according to their weighted net market benefits.
- **Approach B** – a least worst-weighted regrets (LWWR) approach which calculates the 'regrets' of CDPs in each scenario, weights those regrets by the scenario weighting, and determines the maximum 'weighted regrets' across the scenarios. CDPs are ranked in ascending order based on maximum weighted regrets. 'Regrets' represent the differences between the net market benefits of a CDP in a scenario compared with the net market benefits of the least-cost DP in that scenario.

Table 22 shows the net market benefits of each CDP in each scenario, the weighted net market benefits, the worst weighted regrets, and the rankings under each approach.

Table 22 Performance of candidate development paths across scenarios (in $ billion) – ranked in order of weighted net market benefits

CDP	*Scenario-specific net market benefits*			Approach A		Approach B	
	Step Change	*Progressive Change*	*Green Energy Exports*	Weighted net market benefits (WNMB)	WNMB Rank	Worst weighted regrets (WWR)	WWR Rank
14	16.66	13.64	59.60	21.83	1	0.32	13
24	16.61	13.73	59.41	21.82	2	0.28	8
5	16.96	13.84	58.08	21.82	3	0.26	4
18	16.91	13.79	58.31	21.81	4	0.26	2
21	16.67	13.68	59.27	21.80	5	0.30	11
3	16.94	13.71	58.35	21.80	6	0.29	9
20	16.92	13.82	58.05	21.79	7	0.27	5
16	16.91	13.83	57.98	21.78	8	0.28	7
12	16.94	13.71	58.23	21.77	9	0.29	10
19	16.89	14.02	57.27	21.74	10	0.38	17
11	16.80	13.78	58.13	21.73	11	0.26	3
15	16.85	13.67	58.23	21.72	12	0.31	12
10	16.89	13.57	58.36	21.72	13	0.35	14
4	16.75	13.79	58.03	21.70	14	0.27	6
23	16.38	13.93	58.50	21.67	15	0.25	1
8	16.87	13.52	57.85	21.61	16	0.37	16

CDP	*Scenario-specific net market benefits*			Approach A		Approach B	
	Step Change	*Progressive Change*	*Green Energy Exports*	Weighted net market benefits (WNMB)	WNMB Rank	Worst weighted regrets (WWR)	WWR Rank
22	16.66	13.96	57.18	21.60	17	0.40	18
17	16.68	13.33	58.76	21.59	18	0.45	19
6	16.75	13.56	57.76	21.56	19	0.35	15
13	16.90	13.19	57.75	21.47	20	0.51	20
2	16.11	14.40	55.80	21.35	21	0.60	21
1	15.80	12.68	59.83	21.09	22	0.72	23
7	16.70	13.34	53.06	20.74	23	1.01	24
9	15.81	12.95	56.29	20.68	24	0.61	22
25	11.78	12.10	45.05	16.91	25	2.22	25

The table above highlights that the majority of CDPs deliver over $16 billion NPV of net market benefits in the most-likely *Step Change* scenario and over $21 billion when weighted across the three scenarios.

The table shows that there are significant benefits for developing a combination of transmission developments, with 10 of the CDPs within $100 million of weighted net market benefits to the top-ranked CDP. In contrast, delaying all projects to outside each project's respective actionable window (CDP25) is a key outlier, delivering almost $5 billion fewer benefits than the top CDPs, and having over $2 billion of potential regret. While still more beneficial than the counterfactual scenario, slowing down the development of the key transmission projects that are enabling an efficient and effective energy transition is clearly less beneficial than continuing to develop the NEM's transmission system.

A6.6.2 Assessing the actionability of key projects in the CDPs

This section explores the value of individual key projects being delivered within each project's actionable window.

The discussion below focuses on projects that are developed either within or after their respective actionable windows, across the least-cost DPs for all scenarios.

For each of the projects discussed further below, the relative market benefits of that project are first assessed by comparing the least-cost DP in *Step Change* (or an alternative CDP if more appropriate) to a DP that differs only in not delivering the relevant project(s) at all. This is referred to as the 'TOOT' (Take-one-out-at-a-time) approach.

For the purposes of this 2024 ISP, this has been assessed using CDP14 (the CDP with highest weighted net market benefits). The CDP collection always contains a pair of CDPs where the only difference between the two is the delivery of a key relevant project within its actionable window.

Once the relative market benefits of a potential actionable project are assessed, the relative merits of progressing the project at an actionable timing or taking a 'wait-and-see' approach (delaying the project to after its actionable window and allowing at least the next ISP to determine whether to proceed) are then considered. This 2024 ISP has not found any project that would benefit from potential staging, with early works to maintain option value for future progression within the actionable window, or deferral if it is later determined, after completing early works.

Unless otherwise stated, most of the CDP comparisons in the following subsections are against CDP3 (which is the least-cost DP for *Step Change*).

Caution must be taken when adding up the individual relative market benefits of each project as laid out in the TOOTs sections below and comparing it against the ODP's net market benefits. Since there are synergies across multiple projects, the relative market benefits of a project are dependent on delivery of other projects (including their timing). Nevertheless, the TOOTs remain a relevant measure of the individual value of each project, contingent on the rest of the network as modelled in the ODP.

Victoria – New South Wales Interconnector West (VNI West)

As VNI West was identified as an actionable project in the last two ISPs, it has an actionable window of six years from its EISD (from 2029-30 to 2034-35). This augmentation between Victoria and New South Wales sees a transfer capacity increase of 1,935 MW towards New South Wales and 1,669 towards Victoria at a cost of $3,870 million in 2029-30[33]. Every scenario finds VNI West as preferable to develop within its actionable window, with varying timing from 2029-30 in *Step Change*, to 2030-31 under the *Green Energy Exports*, to 2034-35 in *Progressive Change*.

VNI West provides benefits to support the transition of Victoria's energy supply from brown coal to a renewable energy portfolio mix of solar, onshore and offshore wind. By increasing the access to Snowy 2.0 and other supply from the north, additional firming capacity may be avoided, and it enables greater export of surplus Victorian energy once offshore wind is developed to scale (or energy generated in other regions and transferred through the Victorian network). This subsection will first discuss the relative market benefits of this augmentation via TOOT analysis, followed by a discussion of the impact on net market benefits and worst weighted regrets of a delayed augmentation.

Assessing the relative market benefits of VNI West in *Step Change* via TOOT analysis

Table 23 highlights the relative market benefits that VNI West at ODP's timing provides compared to a case without it developed at any point during the outlook period. These benefits result mainly from generator and storage capital deferral and to a lesser extent, fuel costs savings. Overall, VNI West contributes approximately $1.3 billion in net market benefits.

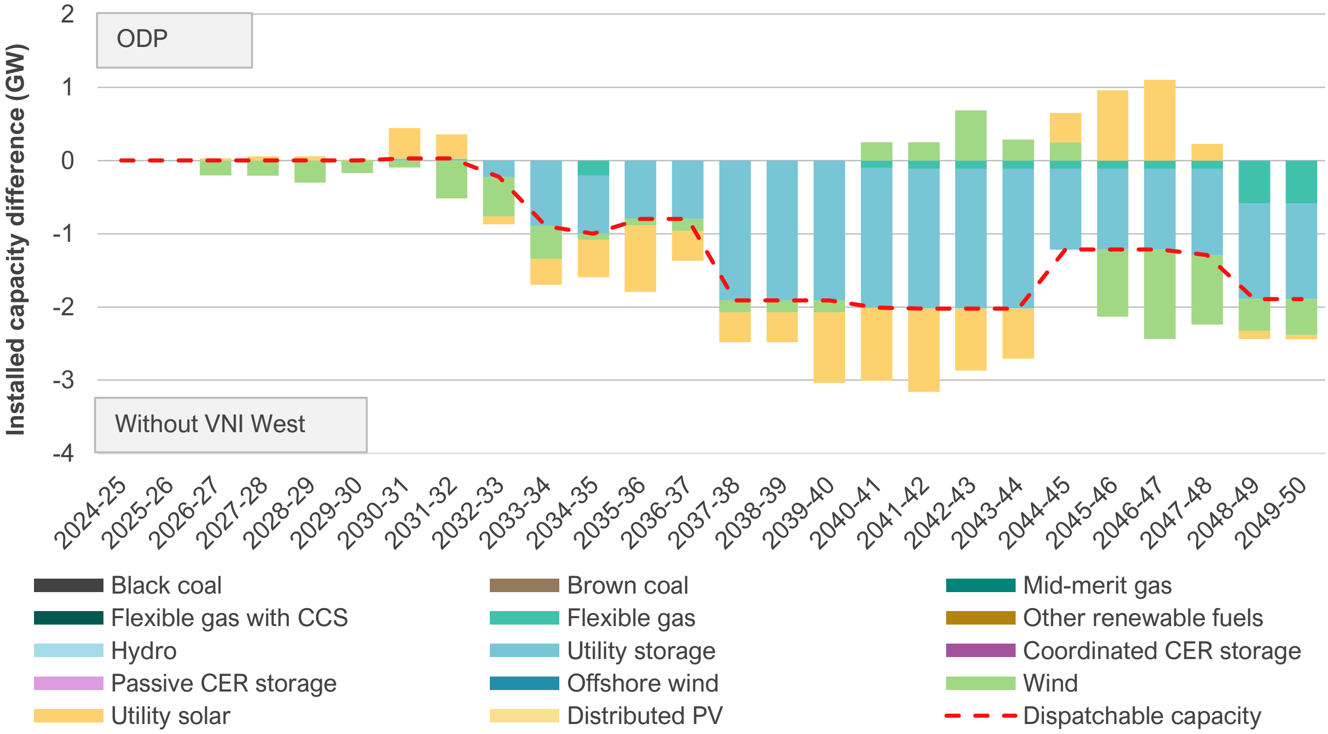
The main source of benefits that arises from developing VNI West within its actionable window is avoided capital expenditure for around 900 MW of storage capacity in Victoria, Tasmania and South Australia, as well as avoiding utility-scale solar capacity, mostly in Victoria (where nearly 800 MW are needed from when the last brown coal units retire). By 2037-38, VNI West results in around 2 GW of avoided storage capacity.

[33] As per AEMO's transmission cost escalation methods described in the 2023 *Transmission Expansion Options Report*, costs in this appendix have been escalated to the relevant year as required, compared to figures provided in Appendix 5.

Table 23 Relative market benefits of VNI West in *Step Change*

Class of market benefits	Relative market benefits (NPV, $ million)
Generator and storage capital deferral	2,787
Fixed operating and maintenance cost savings	264
Fuel cost savings	479
Variable operating and maintenance cost savings	5
Voluntary and involuntary load shedding reductions	105
Other network investment (REZ augmentations)	-50
Gross market benefits excluding emissions	3,590
Emissions reduction benefits	152
Gross market benefits	3,742
Network (Actionable and Future ISP Projects)	-2,422
Total market benefits	1,320

Figure 10 Comparison of capacity with and without VNI West in *Step Change* (at 2029-30)



Assessing the net market benefits of VNI West as an actionable project

The benefits of having VNI West as an actionable project can be assessed by comparing CDP3 with CDP8 (which delays VNI West to outside its actionable window – no earlier than 2035-36). As Table 24 shows, an actionable VNI West delivers $189 million in weighted net market benefits.

Table 24 Comparing net market benefits between CDP3 and CDP8 ($ billion) – VNI West

	CDP3 – with actionable VNI West	CDP8 – without actionable VNI West	Change in net market benefits associated with not actioning the project[A]
Step Change	16.94	16.87	-0.08
Progressive Change	13.71	13.52	-0.20
Green Energy Exports	58.35	57.85	-0.50
Weighted net market benefits	21.80	21.61	-0.19
Ranking based on weighted net market benefits	6	16	

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

In every scenario's least-cost DP, development of VNI West is found to be optimal within its actionable window. If the project is delayed until after its actionable window, then there will be a greater need for firming capacity through deeper storages in Victoria and neighbouring regions. Delivering VNI West to schedule therefore will reduce potential risks associated with the delivery of these alternative resources (that would be at a higher overall system cost as identified above).

Assessing the regrets associated with VNI West as an actionable project

As Table 25 shows, delaying VNI West until after its actionable window increases regrets across all scenarios, and results in an increase in worst weighted regrets by $82 million. The worst weighted regrets come from the risks resulting from under-investing in *Progressive Change*. That is, given the project's preferred timing is within the actionable window in all scenarios, delaying it is introducing a higher system cost, or 'regret', in all scenarios, with the effect being an increase in system costs more than the savings from delaying the investment. As outlined earlier, this is from needing alternative firming capacity in the absence of transfer capacity to share resources when needed with Victoria. This is a similar need to that identified in the 2022 ISP.

Table 25 Weighted and worst weighted regrets of CDP3 and CDP8 ($ billion) – VNI West

	CDP3 – with actionable VNI West	CDP8 – without actionable VNI West	Change in weighted regrets associated with not actioning the project[A]
Step Change	0.01	0.04	0.03
Progressive Change	0.29	0.37	0.08
Green Energy Exports	0.22	0.30	0.07
Worst weighted regrets	0.29	0.37	0.08
Ranking based on worst weighted regrets	9	16	

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

HumeLink

HumeLink was found to be an actionable project in the last two ISPs, and as such, has an actionable window of six years after its EISD of 2026-27. HumeLink increases network capacity by 2,200 MW between South New South

Wales and Central New South Wales with a cost of $4,987 million in 2029-30[34]. Under all scenarios in the 2024 ISP, delivery of HumeLink within its actionable window is found to be optimal, ranging from 2029-30 in both *Step Change* and *Green Energy Exports* to 2030-31 in *Progressive Change* – all before the end of its actionable window (2031-32). This demonstrates that maintaining the project's momentum is in consumers' long-term interest.

HumeLink provides value by increasing the transfer capacity and stability limits between the Snowy Mountains and major load centres of Sydney, Newcastle and Wollongong to support New South Wales following coal retirements, as well as by avoiding more expensive builds to provide the required dispatchable firming capacity and generation. It also facilitates the development of renewable generation in Southern New South Wales. This subsection will first discuss the relative market benefits of this augmentation via TOOT analysis, then discuss the impact on net market benefits and worst weighted regrets of a delayed augmentation.

Assessing the relative market benefits of HumeLink in *Step Change* via TOOT analysis

Table 26 and Figure 11 highlight the relative market benefits that HumeLink provides when delivered at timing under the ODP, compared to a case without HumeLink (at any stage during the outlook period). These benefits accrue mainly from the deferral of generator and storage capital expenditure, and to a lesser extent from fuel costs savings from avoided flexible gas over the outlook period.

Greater access to Snowy 2.0 (and resources across southern New South Wales, Victoria and other inter-connected resources) avoids more expensive flexible gas in Sydney, Newcastle, and Wollongong subregion, and in Victoria. Taking into account the expected cost of the project of $4,987 million in 2029-30, overall, HumeLink contributes roughly $1.6 billion in net market benefits in *Step Change*. The relative market benefits of HumeLink have increased by around $600 million relative to the Draft 2024 ISP, with more significant fuel cost savings as well as the addition of emissions reduction benefits.

Table 26 Relative market benefits of HumeLink in *Step Change*

Class of market benefits	Relative market benefits (NPV, $ million)
Generator and storage capital deferral	3,184
Fixed operating and maintenance cost savings	346
Fuel cost savings	850
Variable operating and maintenance cost savings	46
Voluntary and involuntary load shedding reductions	141
Other network investment (REZ augmentations)	15
Gross market benefits excluding emissions	4,582
Emissions reduction benefits	169
Gross market benefits	4,751
Network (Actionable and Future ISP Projects)	-3,111
Total market benefits	1,640

[34] As per AEMO's transmission cost escalation methods described in the 2023 *Transmission Expansion Options Report*, costs in this appendix have been escalated to the relevant year as required, compared to figures provided in Appendix 5.

Figure 11 Annual relative market benefits of HumeLink in *Step Change* (at 2029-30)

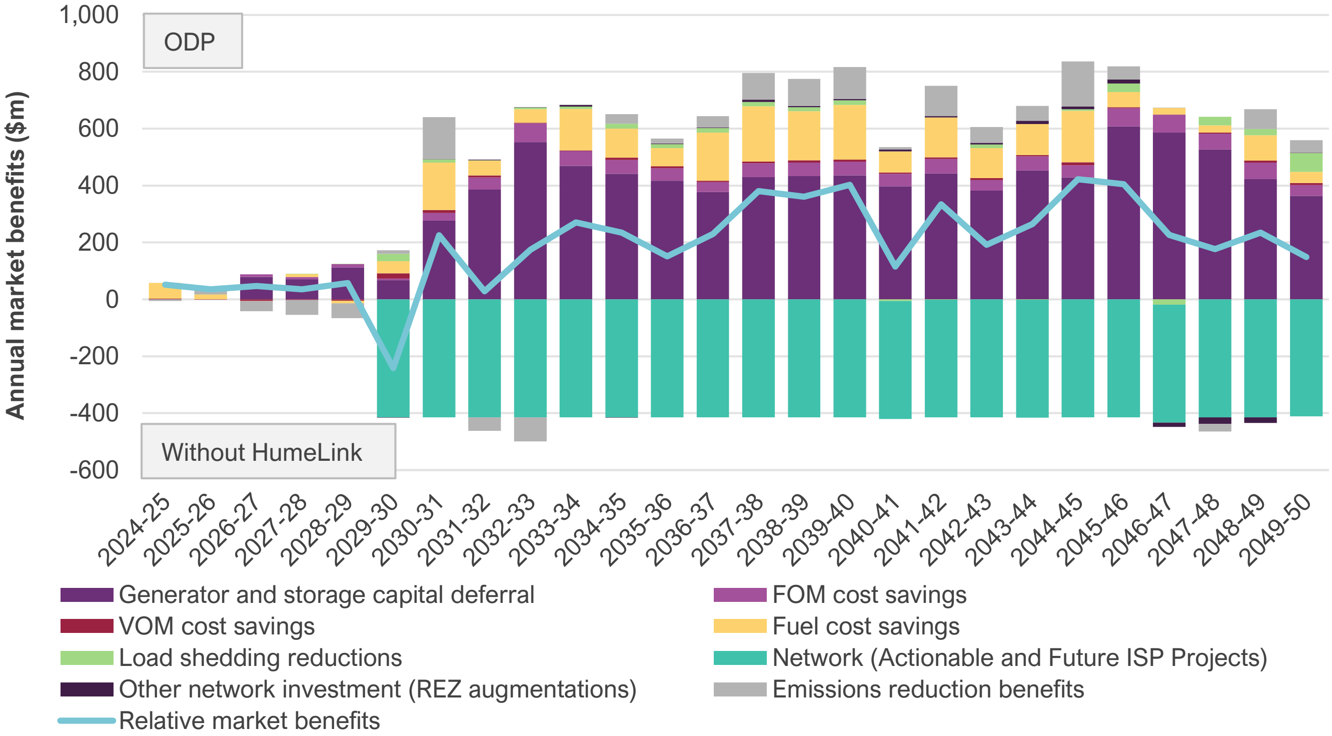
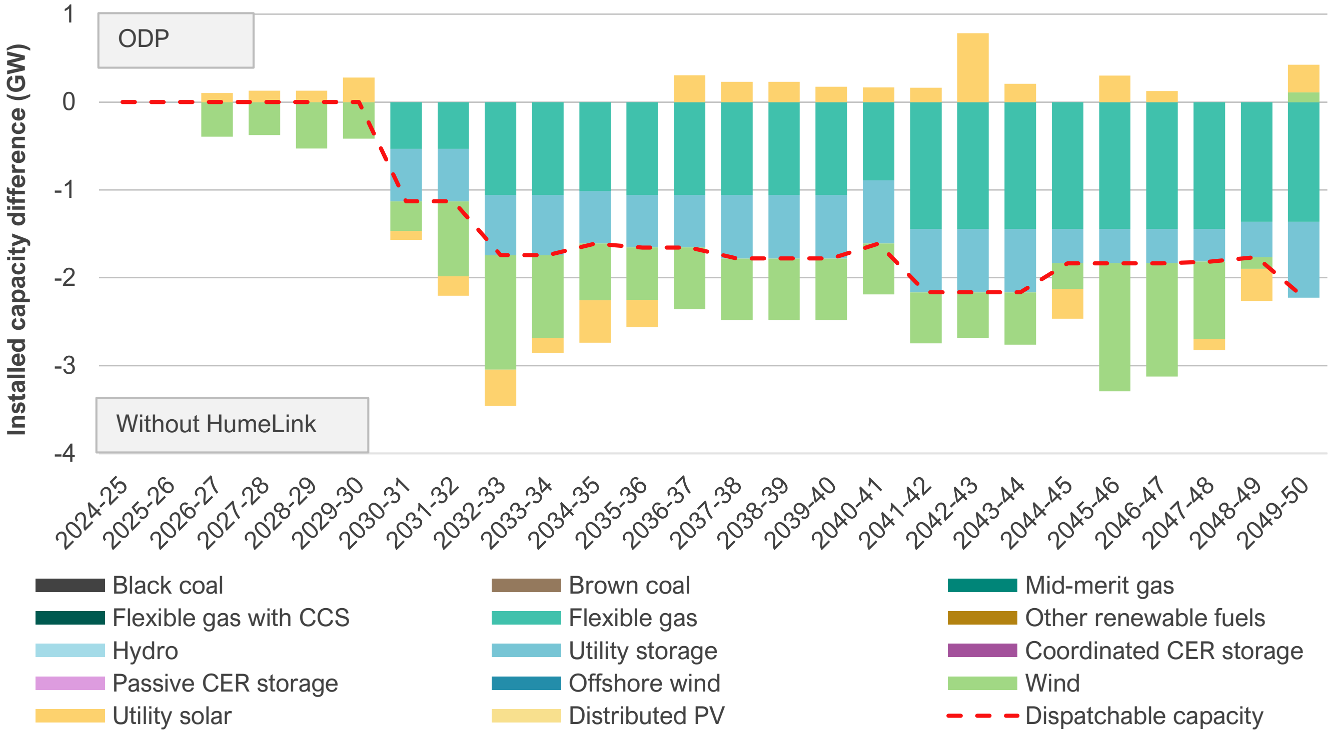


Figure 12 shows that replacing retired coal capacity and meeting increasing demands in the absence of HumeLink requires more capacity development during the first half of the 2030s. Without HumeLink, 1.1 GW of flexible gas in the Sydney, Newcastle, and Wollongong subregion, around 600 MW of deep storage in Northern New South Wales, and up to 740 MW of onshore wind in Northern New South Wales and Queensland are required by 2036-37 to replace the New South Wales coal fleet as it retires.

These builds, which provide dispatchable firming capacity and generation, are the next best alternatives to replacing the retiring coal capacity if HumeLink does not proceed. These additional capacities are not required to be developed or can be deferred to the mid-2040s if HumeLink is developed within its actionable window.

Figure 12 Comparison of capacity with and without HumeLink in *Step Change* (at 2029-30)



Assessing the net market benefits of HumeLink as an actionable project

Aligned with findings in the Draft 2024 ISP, delivering HumeLink within its actionable window is preferred in all of the least-cost DPs and delivers an increase in net market benefits ranging from $244 million in *Step Change* to $5.29 billion in *Green Energy Exports* (see Table 27).

The biggest driver for the need to deliver HumeLink is the inclusion of several policies such as the Powering Australia Plan which targets 82% VRE by 2030 and the modelled carbon budget which further limits coal generation. These factors lead to increases in relative value for the improved REZ access that the project provides, and the increased capacity to share resources between New South Wales and Victoria. Further considerations include the New South Wales renewable generation target as part of the Electricity Infrastructure Roadmap which incentivises VRE build-out in New South Wales, and the Victorian Offshore Wind Target (which increases the amount of potential surplus energy in Victoria at times).

Table 270 compares the net market benefits of CDP3 and CDP7, which differ only on whether HumeLink is delivered within its actionable window or not, for each scenario. Overall, an actionable HumeLink results in an increase in weighted net market benefits of $1.06 billion. This is around $100 million greater than in the Draft 2024 ISP, with a significant increase in net market benefits relative to the Draft 2024 ISP in *Green Energy Exports* and a slight reduction (but still positive) in *Step Change.*

Table 27 Comparing net market benefits between CDP3 and CDP7 ($ billion) – HumeLink

	CDP3 – with actionable HumeLink	CDP7 – without actionable HumeLink	Change in net market benefits associated with not actioning the project[A]
Step Change	16.94	16.70	-0.24
Progressive Change	13.71	13.34	-0.37
Green Energy Exports	58.35	53.06	-5.29
Weighted net market benefits	21.80	20.74	-1.06
Ranking based on weighted net market benefits	6	23	

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

The source of benefits of an actionable HumeLink is similar across the three scenarios – delivering net market benefits throughout the outlook period primarily in avoided generation and storage capital expenditure, and to a lesser extent, avoided fuel costs from operating flexible gas to service loads in the Sydney, Newcastle, and Wollongong subregion.

If HumeLink is delivered after its actionable window, generation and storage investment is required in New South Wales to maintain reliability as coal-fired generators are forecast to retire through the period to 2032-33 (the first year outside HumeLink's actionable window).

Delivering HumeLink at an actionable timing is also necessary to ensure that VNI West can deliver its full range of assessed benefits. If HumeLink is not developed within its actionable window, the effectiveness of VNI West is reduced in *Green Energy Exports*, leading to a commensurate deferral, which results in further benefits being accrued in CDP3 compared to CDP7 due to further deferral of generation capital cost.

Assessing the regrets associated with HumeLink as an actionable project

The regrets associated with delaying HumeLink beyond its actionable window are demonstrated through a comparison of CDP3 versus CDP7 in terms of weighted regrets.

As seen in Table 28, the highest regrets for CDP7 occur under *Green Energy Exports,* even after discounting the magnitude of the regrets by the scenario's lower weighting (15% weighting, the lowest of the three scenarios).

Regrets (defined above as the difference between the net market benefits in a scenario of a CDP compared with the least-cost DP of that scenario) are particularly high in *Green Energy Exports* due to the faster pace of coal retirements forecast in this scenario and to a lesser extent increasing demands (including for hydrogen production). Delays to the delivery of HumeLink to after its actionable window would require alternative generation and storage developments that are more costly. Continuing with HumeLink as an actionable project decreases the regrets across all scenarios, which then reduces worst weighted regrets by $728 million.

Table 28 Weighted and worst weighted regrets of CDP3 and CDP7 ($ billion) – HumeLink

	CDP3 – with actionable HumeLink	CDP7 – without actionable HumeLink	Change in weighted regrets associated with not actioning the project[A]
Step Change	0.01	0.11	0.11
Progressive Change	0.29	0.44	0.16
Green Energy Exports	0.22	1.01	0.79
Worst weighted regrets	0.29	1.01	0.73
Ranking based on worst weighted regrets	9	24	

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

Project Marinus

Project Marinus is a two-stage augmentation with two submarine cables to improve connection to Victoria that would enable improved connection with Tasmania's high quality renewable and hydro resources. The project is represented as two stages representing the development of the first and second cables. Stage 1 and Stage 2 each see an increase of network capacity of 750 MW between Victoria and Tasmania, at a cost of $3,586 million in 2030-31 and $2,728 million in 2037-38 respectively[35].

The project was found to be actionable in the last two ISPs, giving it an actionable window of six years beyond each stage's EISDs. Given the different EISDs[36] (2030-31 for Stage 1 and 2032-33 for Stage 2), Project Marinus Stage 1 would be actionable if its optimal timing takes place before or in 2035-36 and Project Marinus Stage 2 before or in 2037-38.

Every scenario's least-cost DP finds the delivery of Project Marinus Stage 1 to be optimal at its EISD (2030-31). Development of Project Marinus Stage 2 is optimal within its actionable window in *Green Energy Exports* (2032-33) and *Progressive Change* (2036-37), and after its actionable window in *Step Change* (2048-49).

The later optimal timing for Project Marinus Stage 2 in *Step Change* is driven by cost increases for Stage 2, the reduction in available diversity of the Southern Offshore Wind Zone[37] which results in greater offshore wind development in Gippsland, and the influence of forecast load growth within Tasmania which reduces the surplus of Tasmanian renewable energy to export to mainland regions.

Project Marinus (Stage 1 and Stage 2) provides benefits at their timings in the least-cost DP in *Green Energy Export* and *Progressive Change*. It supports growing demands (including for hydrogen production) and the export of Tasmanian generation, driven by the Tasmanian Renewable Energy Target.

This subsection first discusses the relative market benefits (via TOOT analysis), weighted net market benefits, and worst weighted regrets of Project Marinus as a single stage project, then discusses the benefits of the second project stage.

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[35] As per AEMO's transmission cost forecasting approach explained in the 2023 *Transmission Expansion Options Report*, costs in this appendix have been represented for relevant delivery year. Cost estimate values provided in Appendix 5 are represented differently.

[36] Note that the EISDs for both projects have been delayed by a year compared to the Draft 2024 ISP.

[37] The size of Southern Ocean Offshore Wind Zone, declared in March 2024, is significantly smaller than modelled in the 2024 Draft ISP. See https://www.dcceew.gov.au/energy/renewable/offshore-wind/areas/southern-ocean-region.

Assessing the relative market benefits of both stages of Project Marinus in *Step Change* via TOOT analysis

Table 29 and Figure 13 present the relative market benefits of delivering both stages of Project Marinus at their optimal timings based on the CDP that provides the highest weighted net market benefits, applied to the *Step Change* scenario compared to a case without the project. The augmentation delivers gross benefits over the outlook period amounting to $3.4 billion mainly from avoided generator and storage capital costs, fuel costs, and fixed operating and maintenance costs. Overall, Project Marinus Stage 1 and Project Marinus Stage 2 contribute roughly $571 million to the ODP.

Table 29 Relative market benefits of Project Marinus in *Step Change*

Class of market benefits	Relative market benefits (NPV, $ million)
Generator and storage capital deferral	1,879
Fixed operating and maintenance cost savings	89
Fuel cost savings	828
Variable operating and maintenance cost savings	19
Voluntary and involuntary load shedding reductions	203
Other network investment (REZ augmentations)	112
Gross market benefits excluding emissions	3,129
Emissions reduction benefits	278
Gross market benefits	3,407
Network (Actionable and Future ISP Projects)	-2,836
Total market benefits	571

Figure 13 Annual relative market benefits of Project Marinus in *Step Change* (Stage 1 in 2030-31, Stage 2 in 2037-38)

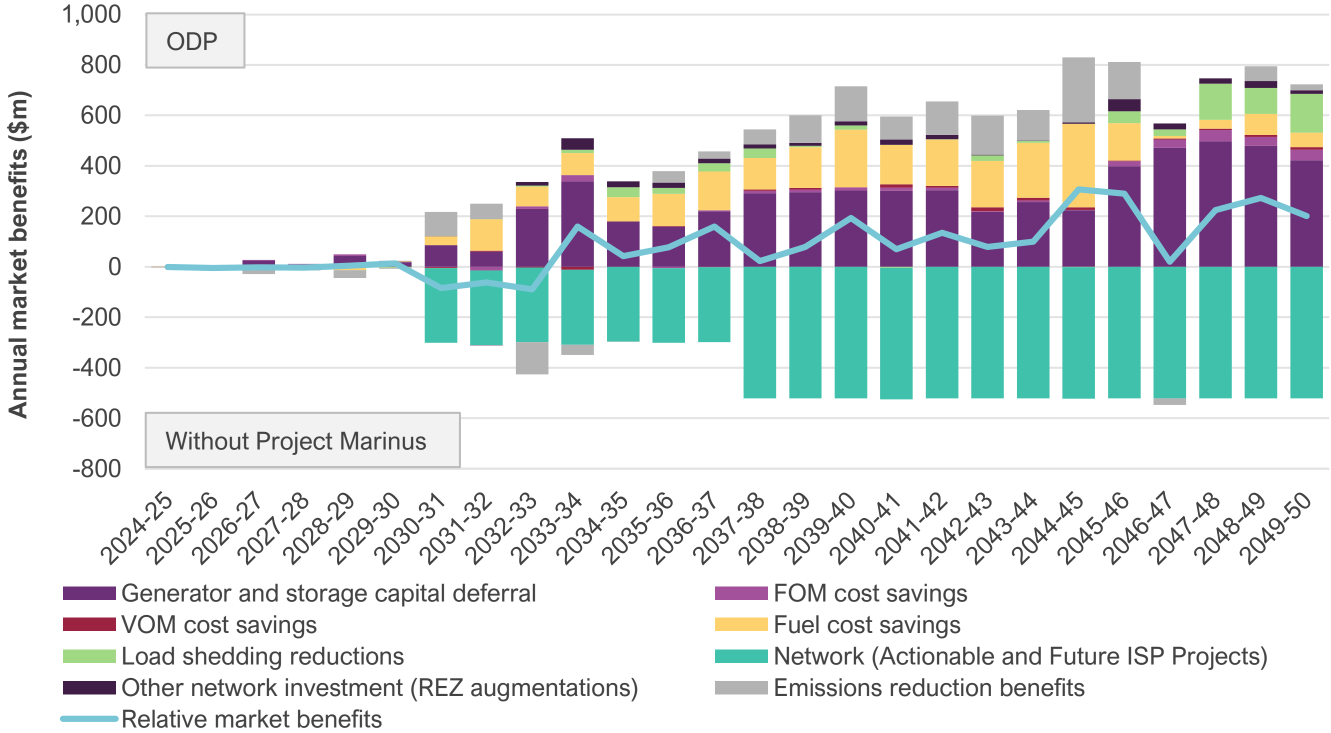
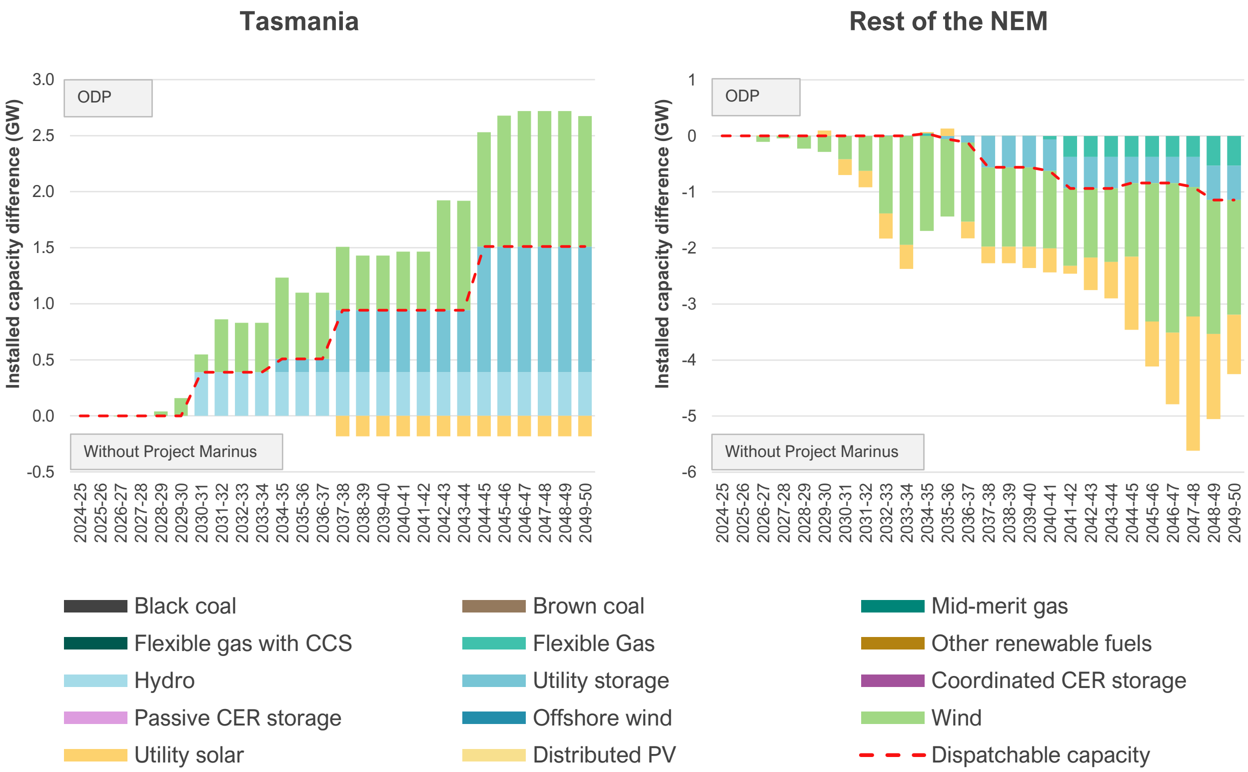


Figure 14 highlights the differences in generation capacity in Tasmania and the rest of the NEM with and without Project Marinus at the specified project timing. From 2029-30, additional hydro capacity in Tasmania is unlocked with the development of Project Marinus Stage 1. As outlined in the 2024 ISP Inputs and Assumptions Workbook[38], Hydro Tasmania is assumed to re-purpose maintenance expenditure to physical works with the development of Project Marinus to increase capacities of some generators within their portfolio, totalling approximately 390 MW in capacity. This is assumed to have no incremental cost (as it is anticipated to be equivalent to the maintenance costs that would otherwise be spent).

This improvement to existing hydro facilities is complemented by the development of additional wind (in North West Tasmania, North East Tasmania, and Central Highlands REZs), as well as utility-scale storage in Tasmania in the late 2030s once Project Marinus' Stage 2 is built (including the development of Cethana in 2034-35, a key component of the Battery of the Nation project).

Figure 14 Comparison of capacity with and without Project Marinus in *Step Change* (Stage 1 in 2030-31, Stage 2 in 2037-38)



Without the development of Project Marinus, additional capacity is required to meet demand in the mainland. This includes higher levels of onshore wind (around 1.4 GW by 2032-33) and also utility solar, mostly in Victoria and to a lesser extent in New South Wales. Project Marinus would instead allow additional Tasmanian renewable generation to support the mainland regions. Nearly 500 MW of deep utility storage capacity is also required in Victoria without Project Marinus by 2037-38, increasing to 760 MW by 2044-45.

[38] See the Flow Path Augmentation Options sheet in the 2024 ISP Inputs and Assumptions Workbook for further details.

Assessing the net market benefits of both stages of Project Marinus as an actionable project

The benefits of delivering Project Marinus within its actionable window can be best observed by comparing CDP14 with CDP13, as seen in Table 30 below.

CDP14 has delivery of both stages of Project Marinus within their actionable windows, whereas CDP13 removes them as actionable projects. For *Green Energy Exports* and *Progressive Change*, which develop Project Marinus Stage 2 within its actionable window in their least-cost optimal development paths, delaying Project Marinus Stage 1 also requires delaying Stage 2, as the former is a pre-requisite for the latter.

Table 30 Comparing net market benefits between CDP14 and CDP13 ($ billion) – Project Marinus

	CDP14 – with actionable Project Marinus	CDP13 – without actionable Project Marinus	Change in net market benefits associated with not actioning the project[A]
Step Change	16.66	16.90	0.25
Progressive Change	13.64	13.19	-0.46
Green Energy Exports	59.60	57.75	-1.84
Weighted net market benefits	21.83	21.47	-0.36
Ranking based on weighted net market benefits	1	20	

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

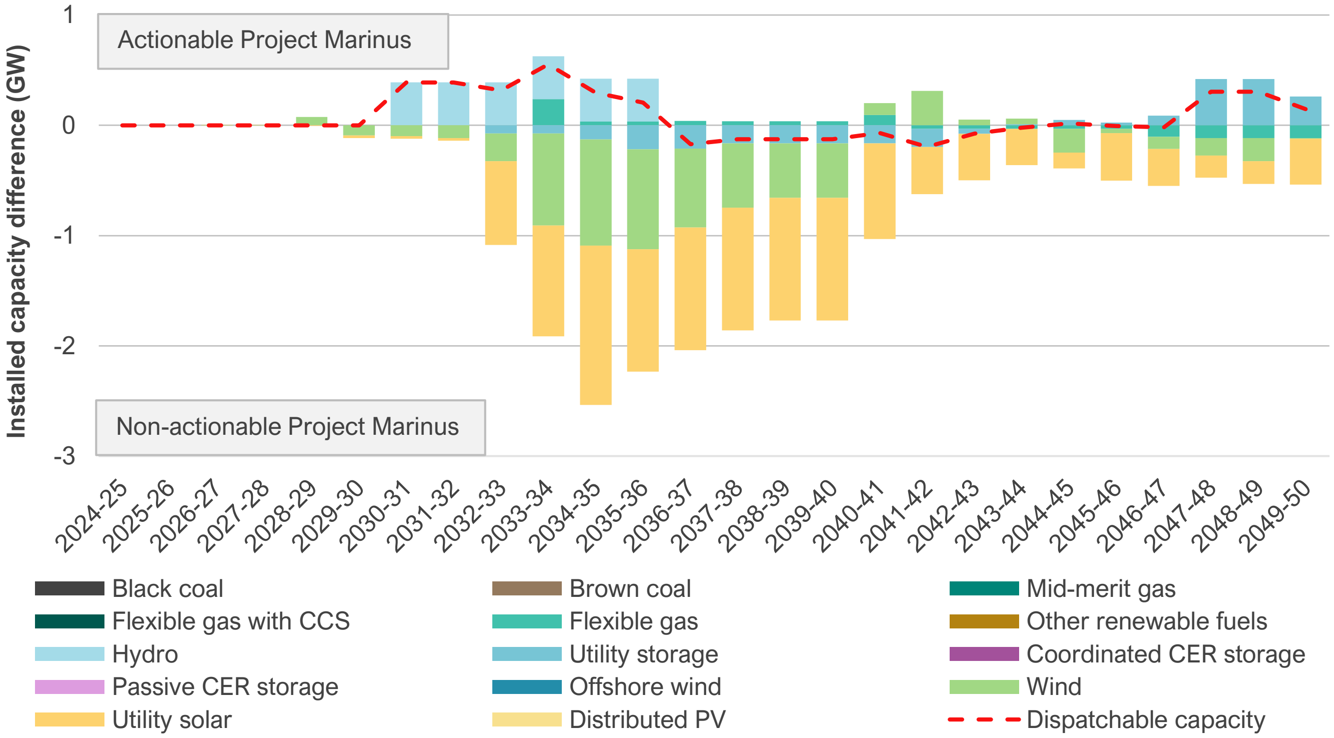
An actionable Project Marinus delivers market benefits in *Progressive Change* ($459 million) and in *Green Energy Exports* ($1.84 billion). In *Step Change*, delivering both stages at an actionable timing result in a decrease in net market benefits of $248 million, due to the later optimal timing of Project Marinus Stage 2 in this scenario. On a weighted net market benefits basis, an actionable Project Marinus results in an increase in weighted net market benefits of $363 million.

As seen in Figure 15, in *Progressive Change,* Project Marinus avoids 1.4 GW of additional utility solar capacity and around 960 MW of additional wind capacity by 2034-35 needed to support electricity and hydrogen production demand.

In *Progressive Change*, the benefits of an actionable Project Marinus stem from the deferral of around 960 MW of wind and 1.4 GW of solar capacity across NEM states, avoided fuel costs, and reduction in emissions and in firming capacity needed to meet demands over the outlook period by allowing higher levels of export of VRE from Tasmania.

Until Project Marinus Stage 1 is built, there is higher levels of curtailment of wind and spilling of hydro generation in Tasmania in *Progressive Change*, limiting Tasmania's capacity to support the mainland during peak periods.

Figure 15 Comparison of capacity with and without an actionable Project Marinus in *Progressive Change*



In *Green Energy Exports*, the benefits of an actionable Project Marinus stem from an increase in the relative share of hydrogen production and green steel production in Tasmania to take advantage of the high-quality resources of the region. By 2034-35, electricity consumption for export hydrogen and green steel production is around 10,300 GWh greater in Tasmania with the augmentations. In their absence, hydrogen production is instead developed across the mainland.

Finally, in *Step Change*, delaying Project Marinus to outside of its actionable windows results in an increase in net market benefits of around $248 million. While delivering Project Marinus Stage 1 at an actionable timing does result in an increase in net market benefits, bringing forward Project Marinus Stage 2 does not defer sufficient wind and solar capacity, and hence decreases the net market benefits of the actionable project.

In addition, in *Step Change* the proposed Cethana pumped hydro project is developed at the same time as Project Marinus Stage 2. Cethana provides deep storage to complement Gippsland offshore and Tasmanian onshore wind production, and reduces system costs to provide accessible storage to store local renewable energy when the South East Victoria transmission corridor is constrained. At other times, this deep storage also helps to increase overall system resilience. The Cethana project is developed in every scenario, in 2044-45 in *Progressive Change* and late 2030s *in Green Energy Exports*.

Assessing the regrets associated with both stages of Project Marinus as an actionable project

Table 31 presents the weighted regrets in each of the scenarios and worst weighted regrets for CDP14 and CDP13. In both, the regrets associated with progressing Project Marinus after its actionable window are largest in *Progressive Change*. Delaying the project is associated with a risk of under-investment relative to the least-cost DP.

Table 31 Weighted and worst weighted regrets of CDP14 and CDP13 ($ billion) – Project Marinus

	CDP14 – with actionable Project Marinus	CDP13 – without actionable Project Marinus	Change in weighted regrets associated with not actioning the project[A]
Step Change	0.13	0.02	-0.11
Progressive Change	0.32	0.51	0.19
Green Energy Exports	0.03	0.31	0.28
Worst weighted regrets	0.32	0.51	0.19
Ranking based on worst weighted regrets	13	20	

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

Assessing the relative market benefits of Project Marinus Stage 2 via TOOT analysis

Table 320 presents the relative market benefits of delivering Project Marinus's Stage 2 at its respective optimal timings in the ODP under *Step Change, Progressive Change* and *Green Energy Exports* compared to a case without the project. It also presents the weighted relative market benefits of the project.

The timing of Project Marinus Stage 2 is significantly delayed in *Step Change* compared to the rest of the scenarios. This TOOT analysis has been applied to all scenarios, given their contribution to the project's net market benefit in the ODP, consistent with the ISP Methodology[39]

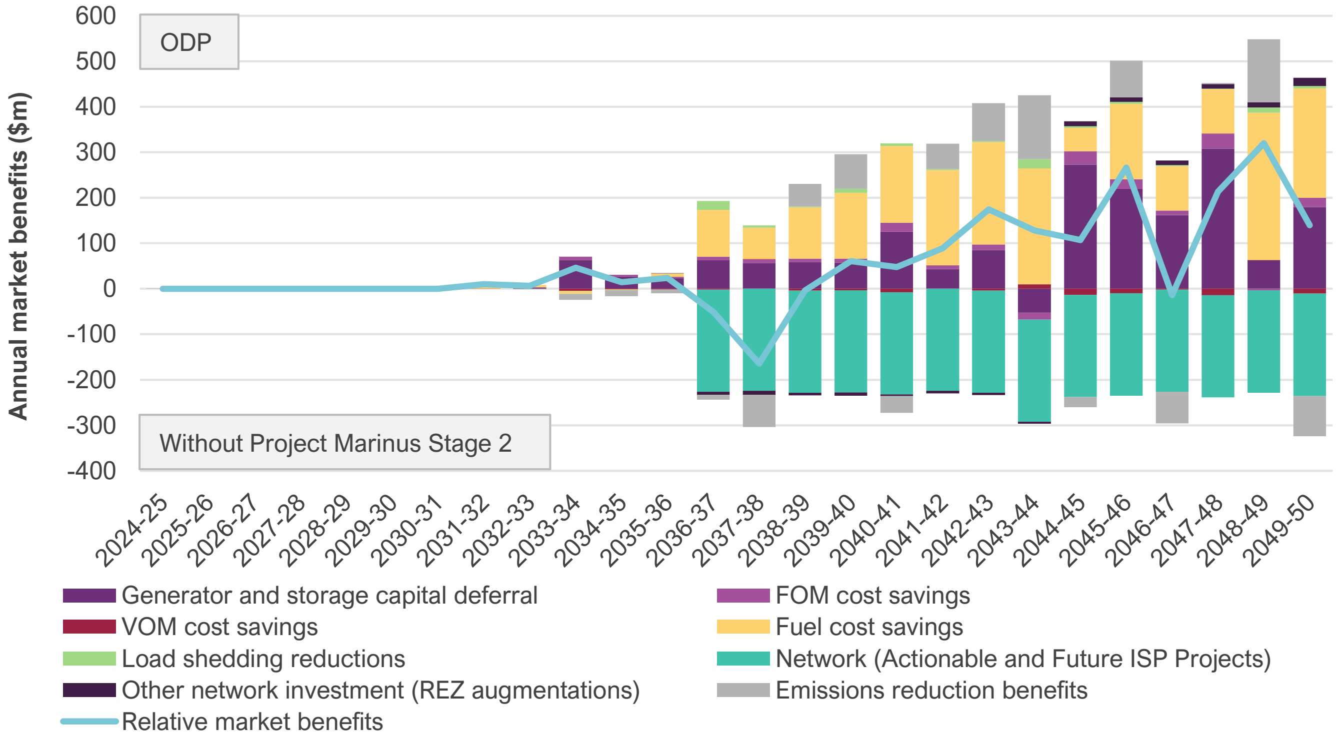
In *Step Change*, delivering the project within its actionable window, rather than never, results in a reduction in relative market benefits of around $313 million. Project Marinus Stage 2 delivers more significant relative market benefits in *Progressive Change* and *Green Energy Exports* in the ODP, amounting to $353 million and $2.8 billion respectively. This is primarily due to fuel cost and generator and storage capital deferral savings. As shown in Figure 16, fuel cost savings represent the most significant component of benefits over the period to the mid-2040s in *Progressive Change*, after which there is a relative increase in generator and storage deferral with the project in place. The project delivers very significant relative market benefits in *Green Energy Exports*, as it avoids significant solar capacity in the mainland in response to the shift of hydrogen load towards Tasmania. On a weighted relative market benefit basis, the project delivers $434 million.

[39] Available at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/isp-methodology-2023/isp-methodology_june-2023.pdf?la=en.

Table 32 Relative market benefits (NPV, $ million) of Project Marinus Stage 2

Class of market benefits	*Step Change*	*Progressive Change*	*Green Energy Exports*	Weighted relative market benefits
Generator and storage capital deferral	-30	503	2,662	597
Fixed operating and maintenance cost savings	12	55	572	114
Fuel cost savings	272	603	35	376
Variable operating and maintenance cost savings	21	-19	24	5
Voluntary and involuntary load shedding reductions	92	27	82	63
Other network investment (REZ augmentations)	-39	4	598	75
Gross market benefits excluding emissions	328	1,173	3,974	1,230
Emissions reduction benefits	155	61	1	92
Gross market benefits	483	1,234	3975	1,322
Network (Actionable and Future ISP Projects)	-796	-880	-1,172	-888
Total market benefits	-313	353	2,804	434

Figure 16 Annual relative market benefits of Project Marinus Stage 2 in *Progressive Change* (Stage 2 at 2036-37)



Assessing the net market benefits of Project Marinus Stage 2 as an actionable project

Table 33 presents the change in net market benefits associated with a delayed Project Marinus Stage 2 beyond its actionable timing. The project does not deliver net market benefits at an actionable timing in *Step Change*, reducing benefits by around $287 million. Although the project is found actionable in the *Progressive Change's* least-cost DP, the inclusion of other actionable projects in CDP3 reduces the benefits of the project's second stage, resulting in the project lowering net market benefits by $70 million. Finally, the project's second stage delivers significant benefits in *Green Energy Exports* as it helps lower the overall development costs associated with hydrogen production for domestic and export use from the 2030s.

Overall, progressing Project Marinus Stage 2 now rather than later increases net market benefits on a weighted basis by $34 million.

Table 33 Comparing net market benefits between CDP14 and CDP3 ($ billion) – Project Marinus Stage 2

	CDP14 – with actionable Project Marinus Stage 2	CDP3 – without actionable Project Marinus Stage 2	Change in net market benefits associated with not actioning the project[A]
Step Change	16.66	16.94	0.29
Progressive Change	13.64	13.71	0.07
Green Energy Exports	59.60	58.35	-1.25
Weighted net market benefits	21.83	21.80	-0.03
Ranking based on weighted net market benefits	1	6	

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

Assessing the regrets associated with Project Marinus Stage 2 as an actionable project

Table 34 presents the weighted regrets in each of the scenarios and worst weighted regrets for CDP14 and CDP3. In both CDPs, the regrets associated with progressing Project Marinus Stage 2 are largest in *Progressive Change*, associated with the risk of over-investment in this scenario. Delaying the project would result in a reduction in worst weighted regrets of around $30 million.

Table 34 Weighted and worst weighted regrets of CDP14 and CDP3 ($ billion) – Project Marinus Stage 2

	CDP14 – with actionable Project Marinus Stage 2	CDP3 – without actionable Project Marinus Stage 2	Change in weighted regrets associated with not actioning the project[A]
Step Change	0.13	0.01	-0.12
Progressive Change	0.32	0.29	-0.03
Green Energy Exports	0.03	0.22	0.19
Worst weighted regrets	0.32	0.29	-0.03
Ranking based on worst weighted regrets	13	9	

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

Progressing Project Marinus as a single actionable project

Based on the analysis above, delivering Project Marinus Stage 2 within its actionable window, rather than never, delivers significant net market benefits of $434 million. Therefore, it is clear that Stage 2 is needed at some point in time, although the optimal timing is not as clear.

Analysis of the benefits of actioning the project's second stage suggests the decision to action Stage 2 now, rather than delaying that decision, is finely balanced. AEMO considered whether Project Marinus was more appropriately identified as a staged project for the purposes of the ISP framework. When considering this, AEMO noted that

CDP14, which includes an actionable Project Marinus Stage 2, maximises weighted net market benefits across the entire CDP collection.

AEMO also noted that the project proponents intend to stage the delivery of the project, as reflected in the different EISDs for each stage included in this analysis. Based on the proposed timing of Stage 2, the 2026 ISP will reassess the actionability of Project Marinus Stage 2 in the same way that the 2024 ISP has reassessed the actionability of all projects that are not yet considered as anticipated or committed projects. The ISP feedback loop will evaluate whether a project or project stage is aligned with the ODP of the most recent ISP. Prior to the feedback loop being completed (which is conducted after the project proponent progresses it through the relevant stage gate of the RIT-T process), the project or stage will continue to be assessed in subsequent ISPs, while the project has not achieved anticipated or committed status.

Finally, in the Draft 2022 ISP consultation, AEMO sought stakeholder feedback specifically on whether Project Marinus should be treated as a single or staged actionable ISP project. AEMO considers that reversing the decision to treat it as a single project in the 2022 ISP, which considered that feedback, should only occur if there is a clear benefit for consumers of such a decision.

On this basis, the 2024 ISP identifies Project Marinus as a single actionable project without staging for the purposes of the ISP framework.

Waddamana to Palmerston transfer capability upgrade

The Waddamana to Palmerston transfer capability upgrade is a new potential actionable ISP project which increases transfer capacity from potential renewable generation development in Tasmania's Central Highlands REZ. The project has an EISD of 2029-30 and is identified as actionable in every scenario at that timing at a cost of $461 million. It provides additional network capacity of 690 MW to support development of renewable generation in central Tasmania.

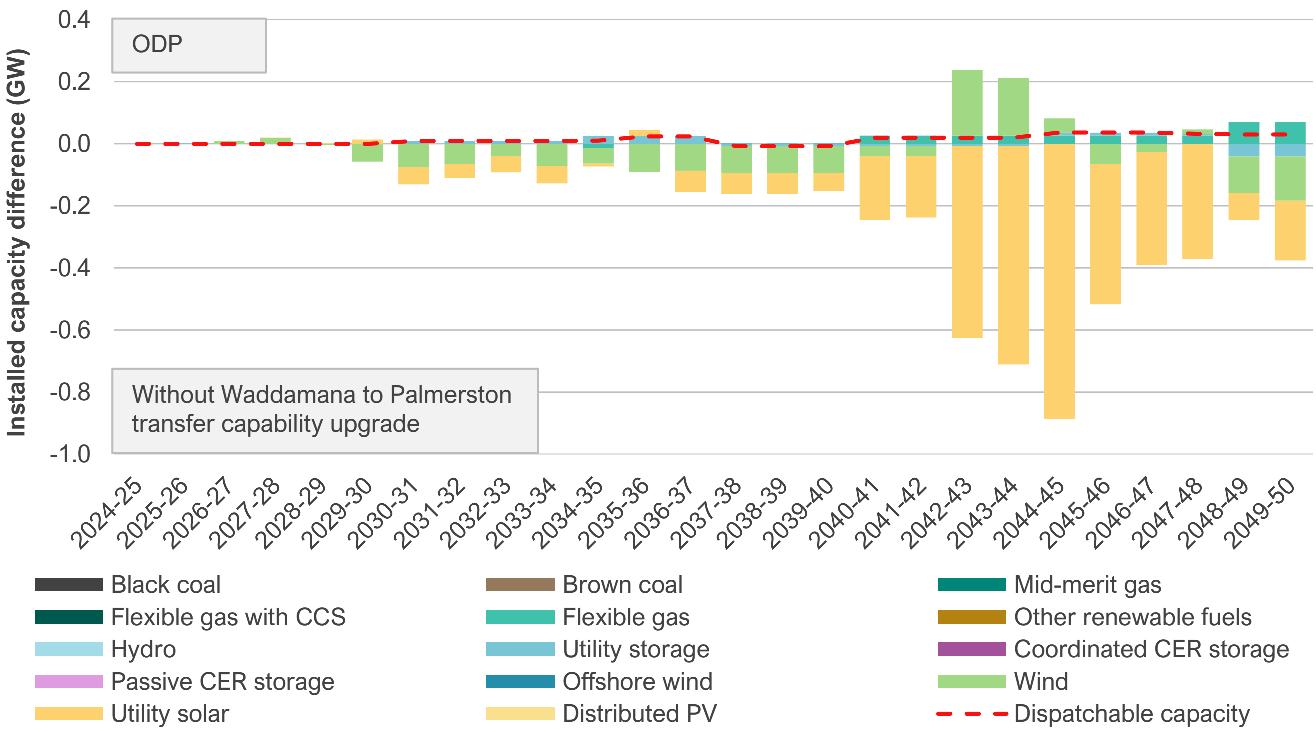
Assessing the relative market benefits of Waddamana to Palmerston transfer capability upgrade via TOOT analysis

As seen in Table 35, the project delivers relative market benefits of $311 million in the ODP under *Step Change*. Most of these savings are from avoided generator capital costs as, without the project, wind generation in the Central Highland REZ is curtailed which would lead to additional wind capacity in Tasmania, and additional wind and utility solar capacity in Victoria are developed as substitutes – particularly in late 2030s when the augmentation defers around 70 MW of solar capacity and 90 MW of wind capacity. This augmentation also shares some of the network upgrades associated with/required for Project Marinus Stage 1, and costings are adjusted to reflect the timings of these components.

Table 35 Relative market benefits of Waddamana to Palmerston transfer capability upgrade in *Step Change*

Class of market benefits	Relative market benefits (NPV, $ million)
Generator and storage capital deferral	247
Fixed operating and maintenance cost savings	47
Fuel cost savings	-5
Variable operating and maintenance cost savings	1
Voluntary and involuntary load shedding reductions	-6
Other network investment (REZ augmentations)	-114
Gross market benefits excluding emissions	170
Emissions reduction benefits	-3
Gross market benefits	167
Network (Actionable and Future ISP Projects)	144
Total market benefits	311

Figure 17 Comparison of capacity with and without Waddamana to Palmerston transfer capability upgrade in *Step Change* (at 2029-30)



Assessing the net market benefits of Waddamana to Palmerston transfer capability upgrade as an actionable project

The net market benefits of the Waddamana to Palmerston transfer capability upgrade can be observed by comparing CDP3 and CDP15, which delays the augmentation to after its actionable window. As Table 36 highlights, the project delivers positive benefits in every scenario – around $50 million in *Progressive Change*, $96 million in *Step Change* and $118 million in *Green Energy Exports*.

Table 36 Comparing net market benefits between CDP3 and CDP15 ($ billion) – Waddamana to Palmerston transfer capability upgrade

	CDP3 – with actionable Waddamana to Palmerston transfer capability upgrade	CDP15 – without actionable Waddamana to Palmerston transfer capability upgrade	Change in net market benefits associated with not actioning the project[A]
Step Change	16.94	16.85	-0.10
Progressive Change	13.71	13.67	-0.05
Green Energy Exports	58.35	58.23	-0.12
Weighted net market benefits	21.80	21.72	-0.08
Ranking based on weighted net market benefits	6	12	

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

In *Step Change*, most savings are from avoided fuel costs, particularly from 2034-35 onwards (soon after its 2031-32 development), emissions reduction benefits, and avoided REZ expansion costs. With a delayed project, additional capacity would instead be developed in North West Tasmania rather than in Central Highlands in 2029-30, which would require an alternative REZ augmentation and the development of more wind capacity across the forecast than would otherwise be required.

Instead, earlier delivery of the project leads to greater dispatch for Tasmanian wind, additional utility solar and wind capacity in Victoria and South East South Australia respectively from 2034-35, offsetting the additional generation from North West Tasmania. It also offsets small amounts of flexible gas generation in the 2030s that would take place otherwise, as the generation is not constrained by network constraints the same way that generation from Tasmania is (via the interconnector flows).

Assessing the regrets associated with Waddamana to Palmerston transfer capability upgrade as an actionable project

Table 37 presents the impact on weighted and worst weighted regrets of delaying the project to after its actionable window. Although quite small, delaying the project increases regrets across all scenarios, particularly in *Step Change* by around $47 million.

Table 37 Weighted and worst weighted regrets of CDP3 and CDP15 ($ billion) – Waddamana to Palmerston transfer capability upgrade

	CDP3 – with actionable Waddamana to Palmerston transfer capability upgrade	CDP15 – without actionable Waddamana to Palmerston transfer capability upgrade	Change in weighted regrets associated with not actioning the project[A]
Step Change	0.01	0.05	0.04
Progressive Change	0.29	0.31	0.02
Green Energy Exports	0.22	0.24	0.02
Worst weighted regrets	0.29	0.31	0.02
Ranking based on worst weighted regrets	9	12	

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

Mid North South Australia REZ Expansion

The Mid North South Australia REZ Expansion is a project identified as a potentially actionable ISP project for the first time. This project represents an augmentation of 1200 MW to the existing network with an EISD of 2029-30, at a cost of $425 million. The project is identified at an actionable timing (2029-30) in both *Step Change* and *Green Energy Exports* and much later in *Progressive Change* (2047-48).

The Mid North limit represents the export limit applied to a subset of South Australian REZs (S3, S4, S5, S6, S7, S8 and S9)[40] to reflect network limitations on how much power generation can be transferred south from these REZs towards Adelaide. The augmentation is driven by the increase in renewable generation in northern areas of South Australia to support growing demands in South Australia including industrial loads such as hydrogen production.

Assessing the relative market benefits of Mid North South Australia REZ Expansion via TOOT analysis

Table 38 presents the benefits that the Mid North South Australia REZ Expansion provides in *Step Change.* Overall, the augmentation contributes approximately $236 million in net market benefits to the ODP in *Step Change*, with the majority being generator and storage capital deferral benefits.

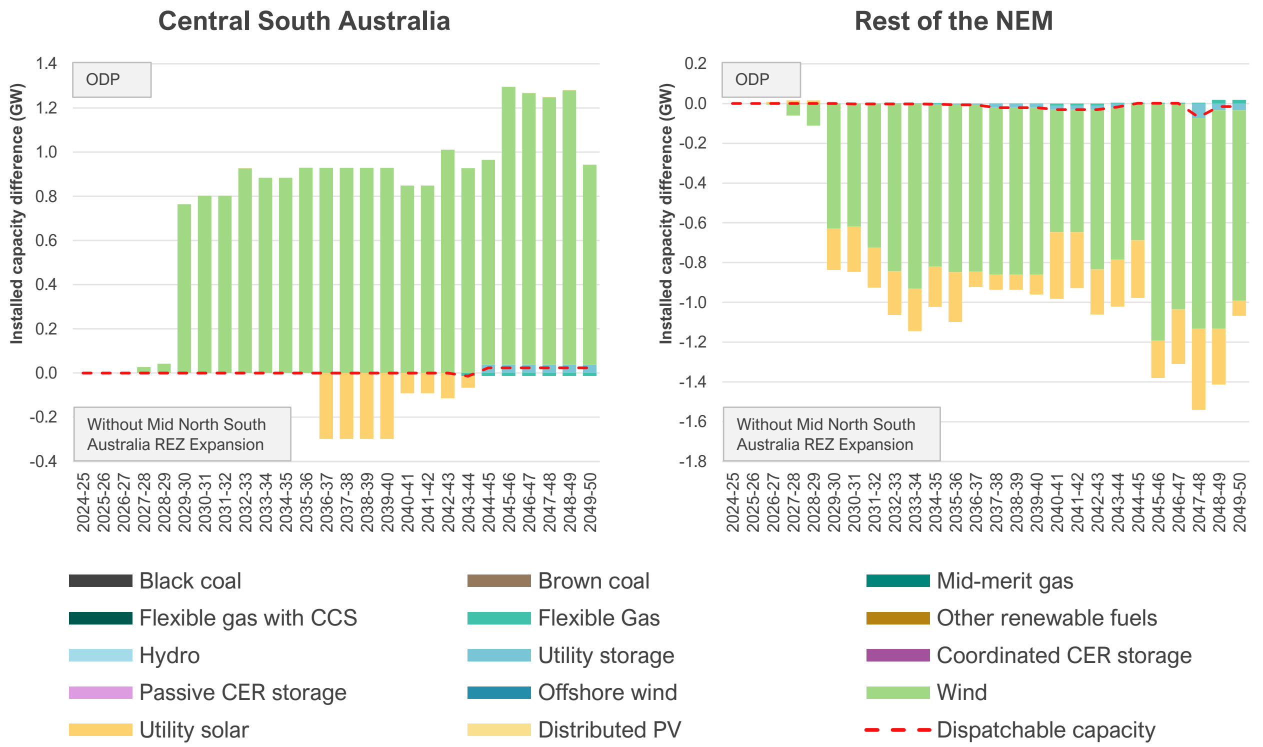
Table 38 Relative market benefits of Mid North South Australia REZ Expansion in *Step Change*

Class of market benefits	Relative market benefits (NPV, $ million)
Generator and storage capital deferral	213
Fixed operating and maintenance cost savings	28
Fuel cost savings	73
Variable operating and maintenance cost savings	7
Voluntary and involuntary load shedding reductions	47
Other network investment (REZ augmentations)	-164
Gross market benefits excluding emissions	204
Emissions reduction benefits	32
Gross market benefits	236
Network (Actionable and Future ISP Projects)	0
Total market benefits	236

As highlighted in Figure 18, delivery of Mid North South Australia REZ Expansion in 2029-30 allows the development of 765 MW of additional wind capacity in Central South Australia which increases to nearly 1.3 GW by 2045-46. Without the augmentation, a similar amount of wind capacity is developed elsewhere in the NEM, mostly in South East South Australia and New South Wales. The augmentation defers up to nearly 300 MW of solar capacity by 2035-36 in New South Wales and Central South Australia.

[40] See Table 36 in the IASR, at https://aemo.com.au/-/media/files/major-publications/isp/2023/2023-inputs-assumptions-and-scenarios-report.pdf?la=en.

Figure 18 Comparison of capacity with and without Mid North South Australia REZ Expansion in *Step Change* (at 2029-30)



Assessing the net market benefits of Mid North South Australia REZ Expansion as an actionable project

The benefits of having Mid North South Australia REZ Expansion as an actionable project are observed by comparing CDP3 with CDP16 (which has the project beyond the actionable window, from 2031-32 onwards). As Table 39 shows, an actionable Mid North South Australia REZ Expansion delivers $18 million in weighted net market benefits.

Table 39 Comparing net market benefits between CDP3 and CDP16 ($ billion) – Mid North South Australia REZ Expansion

	CDP3 – with actionable Mid North South Australia REZ Expansion	CDP16 – without actionable Mid North South Australia REZ Expansion	Change in net market benefits associated with not actioning the project[A]
Step Change	16.94	16.91	-0.03
Progressive Change	13.71	13.83	0.12
Green Energy Exports	58.35	57.98	-0.37
Weighted net market benefits	21.80	21.78	-0.02
Ranking based on weighted net market benefits	6	8	

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

Delivery of the augmentation at an actionable timing provides benefits in *Step Change* ($28 million) and *Green Energy Exports* ($374 million) while resulting in savings of around $120 million if delayed in *Progressive Change*.

The benefits in *Step Change* are mainly from deferred capital expenditure in New South Wales and Victoria. In New South Wales around 140 MW of wind is deferred until 2047-48, and up to 160 MW of solar is deferred until 2035-36 while in Victoria, around 120 MW of wind is deferred to 2032-33 if the augmentation proceeds.

In *Green Energy Exports,* the benefits are more significant, as an actionable augmentation defers around 500 MW of storage capacity (mainly in New South Wales and Victoria) to the mid-2040s. As seen in A6.8.3, if additional industrial load is connected in northern areas of South Australia, then the benefits of the augmentation improve (as observed in *Green Energy Exports*) when delivered at an actionable timing.

Assessing the regrets associated with Mid North South Australia REZ Expansion as an actionable project

As Table 40 shows, delaying Mid North South Australia REZ Expansion until after its actionable window increases regrets across the *Step Change* and *Green Energy Exports* scenarios, but reduces regrets in *Progressive Change*, resulting in an increase in worst weighted regrets of $9 million. The worst weighted regrets come from the risks resulting from under-investing in the project under the *Green Energy Exports* scenario.

Table 40 Weighted and worst weighted regrets of CDP3 and CDP16 ($ billion) – Mid North South Australia REZ Expansion

	CDP3 – with actionable Mid North South Australia REZ Expansion	CDP16 – without actionable Mid North South Australia REZ Expansion	Change in weighted regrets associated with not actioning the project[A]
Step Change	0.01	0.02	0.01
Progressive Change	0.29	0.24	-0.05
Green Energy Exports	0.22	0.28	0.06
Worst weighted regrets	0.29	0.28	-0.01
Ranking based on worst weighted regrets	9	7	

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

New England REZ Network Infrastructure Project

The New England REZ Network Infrastructure Project [41] was identified as an actionable New South Wales project in the *2022 ISP*, therefore it has an actionable window of four years beyond its EISD of 2028-29. It is a proposed 500 kilovolts (kV) project between central and northern New South Wales to access renewable generation from Northern New South Wales, providing a more cost-effective approach to facilitate wind and solar development in New South Wales to meet a growing load and achieve state and federal renewable energy targets. The project includes three potential stages; reference to the project therefore refers to the collection of options outlined in this subsection.

In this 2024 ISP, three transmission options have been considered for the New England REZ – two stages of the New England REZ Network Infrastructure Project, which provide upgrades to the transfer capacity of the Central New South Wales to Northern New South Wales flow path, as well as New England REZ Extension, which further

[41] In the 2022 ISP, New England REZ Network Infrastructure Project was two separate augmentations – CNSW-NNSW Option 6 and 6A. A further augmentation (the New England REZ Extension) was considered a future ISP Project.

increases transfer capacity from New England REZ (see Table 41). The first stage of the New England REZ Network Infrastructure Project is a pre-requisite to the other two upgrades.

The delivery of New England REZ Transmission Link 1 is found to be actionable in all scenarios, with optimal timings at its EISD (2028-29) in *Green Energy Exports* and *Step Change* and a year later in 2029-30 in *Progressive Change*. The second stage (New England REZ Transmission Link 2) is optimal to be developed after its actionable window in all scenarios, with optimal timings of 2034-35 in *Green Energy Exports* and *Step Change* and 2041-42 in *Progressive Change*. The New England REZ Extension is identified to be optimal at its EISD of 2028-29 in *Green Energy Exports*, at 2030-31 (still within its actionable window) in *Step Change*, and at 2039-40 in *Progressive Change*.

AEMO has identified all three transmission augmentations as part of one 'Actionable NSW Project' as EnergyCo is undertaking an overarching program to deliver them, including concerted stakeholder and community engagement across the three projects, and these projects are progressing under the New South Wales framework rather than the ISP framework.

Table 41 New England REZ Network Infrastructure Project options

Option	EISD	Cost[A]	CNSW-NNSW flow path capacity increase	New England REZ transmission capacity increase
New England REZ Transmission Link 1	2028-29	$1,955 million (*Green Energy Exports* and *Step Change*, 2028-29) $1,935 million (*Progressive Change*, 2029-30)	3,000 MW	2,000 MW
New England REZ Extension (Pre-requisite: New England REZ Transmission Link 1)	2028-29	$399 million (*Green Energy Exports*, 2028-29) $405 million (*Step Change*, 2030-31) $402 million (*Progressive Change*, 2039-40)	-	1,000 MW
New England REZ Transmission Link 2 (Pre-requisite: New England REZ Transmission Link 1)	2032-33	$1,623 million (*Green Energy Exports* and *Step Change*, 2034-35) $1,605 million (*Progressive Change*, 2041-42)	3,000 MW	3,000 MW

A. As per AEMO's transmission cost escalation methods in the 2023 *Transmission Expansion Options Report*, costs in this column are based on the optimal timings of the options in each scenario, and as such may differ by scenario.

This subsection will first discuss the relative market benefits of this augmentation via TOOT analysis, then discuss the impact on net market benefits and worst weighted regrets of a delayed augmentation.

Assessing the relative market benefits of New England REZ Network Infrastructure Project in *Step Change* via TOOT analysis

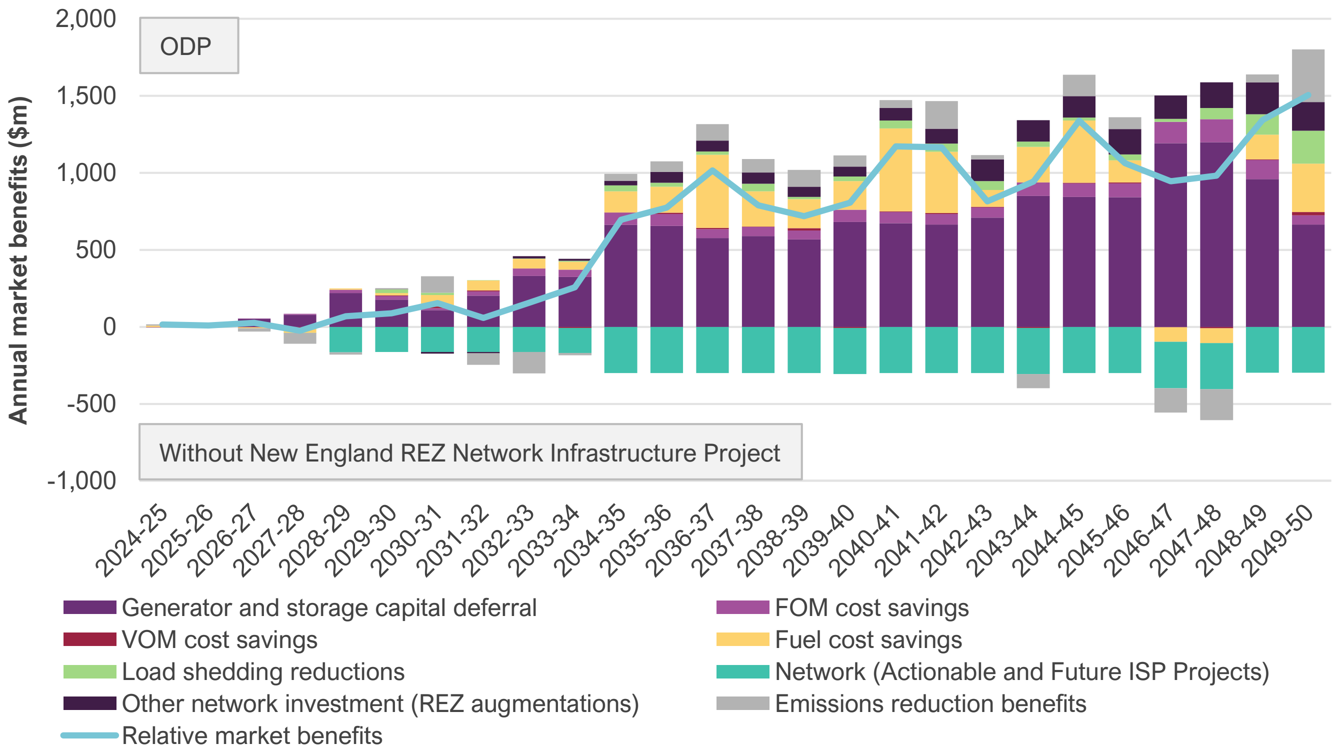
Table 42 and Figure 19 present the benefits that all stages of New England REZ Network Infrastructure Project provide in *Step Change*[42]. Overall, these augmentations contribute roughly $5.1 billion in net market benefits in *Step Change*, most of which comes from generator and storage capital deferrals as well as fuel cost savings.

[42] Due to the pre-requisite delivery requirements, TOOT analysis of the New England REZ Transmission Link 1 also requires removal of the New England REZ Transmission Link 2 and New England REZ Extension.

Table 42 Relative market benefits of New England REZ Network Infrastructure Project in *Step Change*

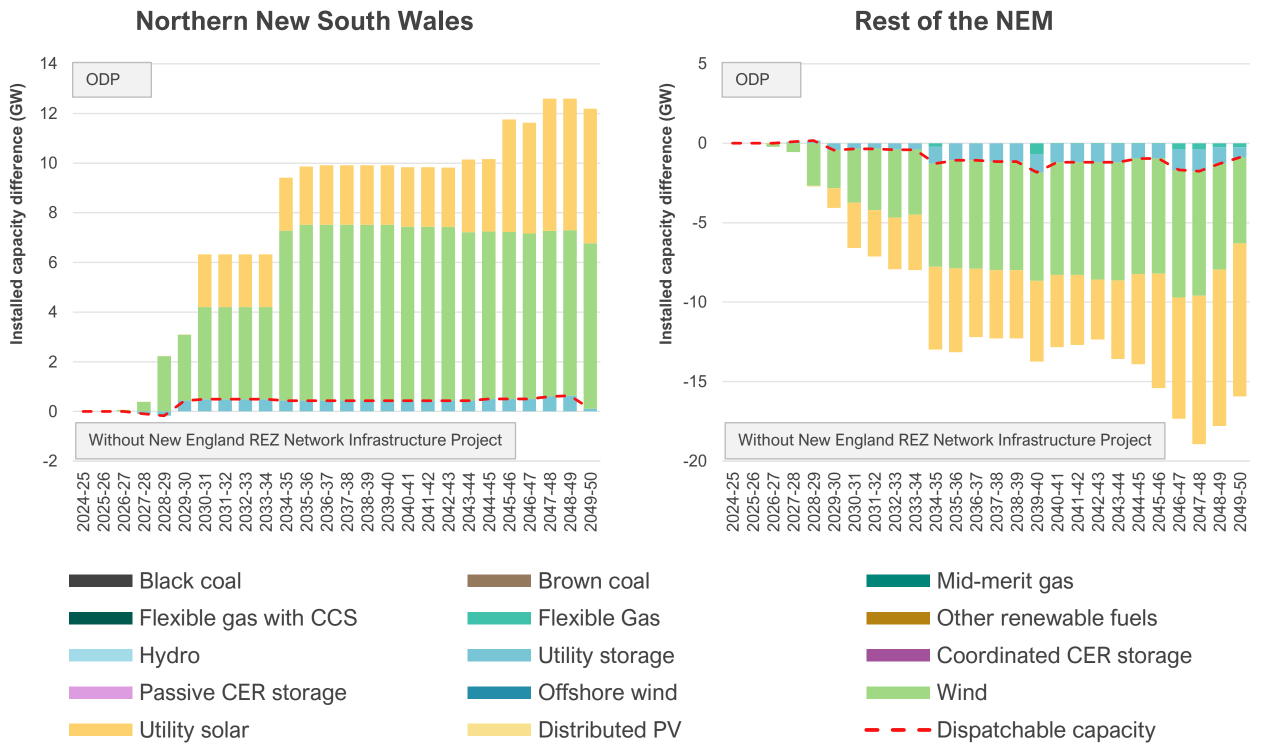
Class of market benefits	Relative market benefits (NPV, $ million)
Generator and storage capital deferral	4,364
Fixed operating and maintenance cost savings	499
Fuel cost savings	1,251
Variable operating and maintenance cost savings	25
Voluntary and involuntary load shedding reductions	295
Other network investment (REZ augmentations)	511
Gross market benefits excluding emissions	6,946
Emissions reduction benefits	148
Gross market benefits	7,093
Network (Actionable and Future ISP Projects)	-1,987
Total market benefits	5,106

Figure 19 Annual relative market benefits of New England REZ Network Infrastructure Project in *Step Change* (Link 1 in 2028-29, Link 2 in 2034-35, New England REZ Extension in 2030-31)



With the New England REZ Network Infrastructure Project, additional wind, solar, and utility storage capacity (7 GW, 2 GW and 400 MW, respectively) are developed in New England REZ, taking advantage of the additional connectivity provided by the project.

Figure 20 Comparison of capacity with and without New England REZ Network Infrastructure Project in *Step Change* (Link 1 in 2028-29, Link 2 in 2034-35, New England REZ Extension in 2030-31)



Without the New England REZ Network Infrastructure Project in *Step Change*, additional wind and solar capacity are required mainly from Central West Orana which already sees development; see the following section.

Assessing the net market benefits of the New England REZ Transmission Link 1 and New England REZ Extension as actionable projects

The regrets associated with delaying the New England REZ Transmission Link 1 and New England REZ Extension augmentation beyond their actionable timings[43] are best demonstrated via a comparison of CDP3 with CDP9 (which is similar to CDP3 but without these two projects as actionable projects); see Table 43.

[43] Note that due to pre-requisites, assessing New England REZ Transmission Link 1 at a non-actionable timing also requires removing New England REZ Extension as an actionable project.

Table 43 Comparing net market benefits between CDP3 and CDP9 ($ billion) – New England REZ Transmission Link 1 and New England REZ Extension

	CDP3 – with actionable New England REZ Transmission Link 1 and New England REZ Extension	CDP9 – without actionable New England REZ Transmission Link 1 and New England REZ Extension	Change in net market benefits associated with not actioning the projects[A]
Step Change	16.94	15.81	-1.13
Progressive Change	13.71	12.95	-0.76
Green Energy Exports	58.35	56.29	-2.06
Weighted net market benefits	21.80	20.68	-1.12
Ranking based on weighted net market benefits	6	24	

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

In all scenarios, delaying New England REZ Transmission Link 1 and New England REZ Extension beyond their actionable windows (to 2032-33) sees a reduction in weighted net market benefits amounting to a $1.12 billion. A delay in the delivery of these augmentations leads to an increase in generator and storage capital expenditure throughout the outlook period.

Delivery of New England REZ Transmission Link 1 provides 2 GW uplift of the New England REZ transmission network, separate to the additional 1 GW of capacity provided by the New England REZ Extension. The augmentation also reduces curtailment of existing generation in New England.

Further augmentation of the Central West Orana network beyond the committed 4.5 GW upgrade (called Central-West Orana REZ Extension augmentation) is only required in the 2040s. This additional augmentation of the Central-West Orana REZ (beyond the 4.5 GW upgrade that is already anticipated by 2028-29) would be preferable to bring forward, if the New England REZ Transmission Link 1 was delayed to 2032-33 (just beyond the project’s actionable window).

Once the New England REZ Transmission Link 1 (and the associated uplift in the New England REZ transmission network) is developed by 2032-33, it reduces generation curtailment and allows further generation development in the New England REZ. Delaying these augmentations leads to increased expenditure and more concentrated development in Central-West Orana over the outlook period.

Compared to the Draft 2024 ISP, benefits associated with the delivery of New England REZ Transmission Link 1 and New England REZ Extension within their actionable windows has increased as it is now also beneficial in *Progressive Change*. In the Draft 2024 ISP, these augmentations were not required until the mid-2030s in *Progressive Change* as there were no further generation builds in the New England REZ until then.

However, updates to the timings of committed and actionable transmission upgrades to the Central-West Orana REZ have shifted more VRE developments to the New England REZ in the 2020s, relative to the Draft 2024 ISP, emphasising the need for earlier transmission augmentations and increasing the relative benefits compared to if these augmentations were delayed to outside their actionable windows in all scenarios.

Assessing the regrets associated with New England REZ Transmission Link 1 and New England REZ Extension as actionable projects

Table 44 shows that not delivering New England REZ Transmission Link 1 and New England REZ Extension within their actionable windows (from CDP3 to CDP9) results in an increase in weighted regrets in all scenarios, highlighting the risks of under-investing in transmission upgrades for the New England REZ. Delivering these two projects within their actionable windows reduces the worst weighted regrets by $321 million.

Table 44 Weighted and worst weighted regrets of CDP3 and CDP9 ($ billion) – New England REZ Transmission Link 1 and New England REZ Extension

	CDP3 – with actionable New England REZ Transmission Link 1 and New England REZ Extension	CDP9 – without actionable New England REZ Transmission Link 1 and New England REZ Extension	Change in weighted regrets associated with not actioning the project[A]
Step Change	0.01	0.49	0.49
Progressive Change	0.29	0.61	0.32
Green Energy Exports	0.22	0.53	0.31
Worst weighted regrets	0.29	0.61	0.32
Ranking based on worst weighted regrets	9	22	

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

Assessing the net market benefits of the New England REZ Extension as an actionable project

The benefits and regrets associated with delaying the New England REZ Extension beyond its actionable window are best demonstrated via a comparison of CDP3 versus CDP11, which defers the augmentation until after its actionable window. This upgrade comes in an optimal timing of 2028-29 in the least-cost DP for *Green Energy Exports* and 2030-31 in *Step Change*, both within the actionable window, but only in 2039-40 in *Progressive Change*.

As Table 45 shows, an actionable timing for the New England REZ Extension improves net market benefits in *Step Change* and *Green Energy* Exports ($144 million and $218 million, respectively), but reduces net market benefits by $60 million in *Progressive Change*. This results in an overall increase of $69 million with an actionable timing on a weighted net market benefits basis.

Table 45 Comparing net market benefits between CDP3 and CDP11 ($ billion) – New England REZ Extension

	CDP3 – with actionable New England REZ Extension	CDP11 – without actionable New England REZ Extension	Change in net market benefits associated with not actioning the project[A]
Step Change	16.94	16.80	-0.14
Progressive Change	13.71	13.78	0.06
Green Energy Exports	58.35	58.13	-0.22
Weighted net market benefits	21.80	21.73	-0.07
Ranking based on weighted net market benefits	6	11	

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

Assessing the regrets associated with New England REZ Extension as an actionable project

Table 46 below presents the weighted regrets and worst weighted regrets of both CDP3 and CDP11. Delaying the delivery of the project beyond its actionable window increases regrets in *Step Change* and *Green Energy Exports*. The relative risk of under-investing in *Green Energy Exports* exceeds the risk of over-investing in *Progressive Change* in terms of weighted regrets. As such, there is an increase in weighted regret of $25 million if the New England REZ Extension was not delivered at an actionable timing.

Table 46 Weighted and worst weighted regrets of CDP3 and CDP11 ($ billion) – New England REZ Extension

	CDP3 – with actionable New England REZ Extension	CDP11 – without actionable New England REZ Extension	Change in weighted regrets associated with not actioning the project[A]
Step Change	0.01	0.07	0.06
Progressive Change	0.29	0.26	-0.03
Green Energy Exports	0.22	0.25	0.03
Worst weighted regrets	0.29	0.26	-0.03
Ranking based on worst weighted regrets	9	3	

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

Hunter-Central Coast REZ Network Infrastructure Project

The Hunter-Central Coast REZ Network Infrastructure Project is newly identified potential actionable project in the 2024 ISP. The project increases the REZ network limit by 500 MW at a cost of $59 million, with an EISD of 2029-30[44]. The augmentation is found optimal at its EISD in *Progressive Change* and *Green Energy Exports*, and in 2030-31 (still within the actionable window) in *Step Change*.

Assessing the relative market benefits of Hunter-Central Coast REZ Network Infrastructure Project via TOOT analysis

Table 47 presents the relative market benefits to ODP in *Step Change*, with $60 million identified, mostly from generator and storage capital savings, as well as fuel cost savings. The project effectively avoids additional installed capacity in the Central-West Orana and South West NSW REZs, as well as further transmission development in Central-West Orana.

[44] EnergyCo provided an updated project proponent date of December 2027 to AEMO in June 2024. This was not incorporated in the ISP modelling due to modelling timeframes, and the modelling includes the earliest in service date of 2029-30 as included in the 2023 *Transmission Expansion Options Report*.

Table 47 Relative market benefits of Hunter-Central Coast REZ Network Infrastructure Project in *Step Change*

Class of market benefits	Relative market benefits (NPV, $ million)
Generator and storage capital deferral	57
Fixed operating and maintenance cost savings	7
Fuel cost savings	18
Variable operating and maintenance cost savings	2
Voluntary and involuntary load shedding reductions	15
Other network investment (REZ augmentations)	-42
Gross market benefits excluding emissions	58
Emissions reduction benefits	2
Gross market benefits	60
Network (Actionable and Future ISP Projects)	0
Total market benefits	60

Assessing the net market benefits of Hunter-Central Coast REZ Network Infrastructure Project as an actionable project

As seen in Table 48, the augmentation delivers modest benefits across all scenarios, in particular in *Green Energy Exports* where delaying the project reduces net market benefits by around $124 million. Most benefits are capital cost savings from deferring around 116 MW of storage capacity to the early to mid-2040s and nearly 700 MW of wind generation in Southern New South Wales by a year.

Table 48 Comparing net market benefits between CDP3 and CDP12 ($ billion) – Hunter-Central Coast REZ Network Infrastructure Project

	CDP3 – with actionable Hunter-Central Coast REZ Network Infrastructure Project	CDP12 – without actionable Hunter-Central Coast REZ Network Infrastructure Project	Change in net market benefits associated with not actioning the project[A]
Step Change	16.94	16.94	0.00
Progressive Change	13.71	13.71	-0.01
Green Energy Exports	58.35	58.23	-0.12
Weighted net market benefits	21.80	21.77	-0.02
Ranking based on weighted net market benefits	6	9	

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

Assessing the regrets associated with Hunter-Central Coast REZ Network Infrastructure Project as an actionable project

Table 49 presents the small impact on weighted and worst weighted regrets of not actioning the project. Delaying the project marginally increases regrets across all scenarios, particularly in *Green Energy Exports* by just $19 million. Overall, weighted net market benefits change by just $4 million.

Table 49 Weighted and worst weighted regrets of CDP3 and CDP12 ($ billion) – Hunter-Central Coast REZ Network Infrastructure Project

	CDP3 – with actionable Hunter Central Coast REZ Extension	CDP12 – without actionable Hunter-Central Coast REZ Extension	Change in weighted regrets associated with not actioning the project[A]
Step Change	0.01	0.01	0.00
Progressive Change	0.29	0.29	0.00
Green Energy Exports	0.22	0.24	0.02
Worst weighted regrets	0.29	0.29	0.00
Ranking based on worst weighted regrets	9	10	

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

Sydney Ring North (Hunter Transmission Project)

This augmentation was classified as an Actionable NSW Project in the 2022 ISP, hence its actionable window is four years from its EISD. Hunter Transmission Project provides an upgrade of 5,000 MW to the northern limit of the Central New South Wales to Sydney, Newcastle, and Wollongong flow path and has an EISD at 2028-29[45] with a cost of $1178 million[46].

The optimal timing across scenarios is always within its actionable window – its delivery is optimal at its EISD (2028-29) in *Green Energy Exports* and *Step Change* and in 2030-31 in *Progressive Change.*

As New South Wales coal plants retire, the Hunter Transmission Project provides increased capability to continue to supply loads in the Sydney, Newcastle, and Wollongong subregion by resources outside of that subregion. Without the augmentation, firming capacity would be required to be developed within the load centre in all scenarios (in particular flexible gas).

This subsection first discusses the relative market benefits of this augmentation via TOOT analysis, then discuss the impact on net market benefits and worst weighted regrets of a delayed augmentation.

Assessing the relative market benefits of Hunter Transmission Project in *Step Change* via TOOT analysis

As Table 50 and Figure 21 show, Hunter Transmission Project delivers benefits over the outlook period in the ODP for *Step Change*. The majority of these benefits comes from generator and storage capital deferral, fuel cost savings, and avoided costs associated with using DSP in the Sydney, Newcastle, and Wollongong subregion.

Overall, Hunter Transmission Project contributes roughly $3 billion to the ODP in *Step Change*. There has been a reduction of $1.2 billion in capital expenditure benefits relative to the Draft 2024 ISP as newly committed and anticipated projects and the expanded Capacity Investment Scheme's dispatchable capacity targets affect the development of capacity across New South Wales. Additionally, the 2024 ISP includes updates to the distribution

[45] Note that the EISD is now one year later than the EISD reported in the Draft 2024 ISP, on updated advice from the project proponent.

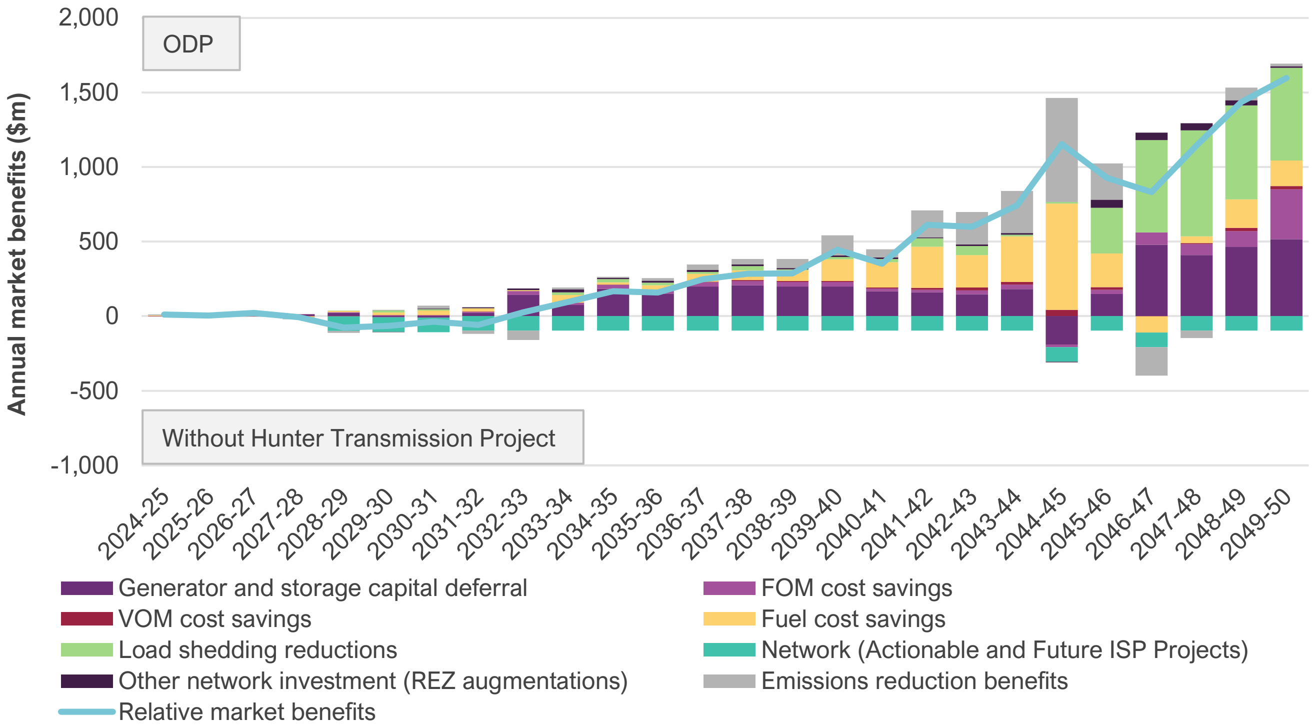
[46] As per AEMO's transmission cost escalation methods described in the 2023 *Transmission Expansion Options Report*, costs in this appendix have been escalated to the relevant year as required, compared to figures provided in Appendix 5.

of New South Wales regional demand in the subregions, as detailed in section A6.3. Despite this reduction in benefits, large relative market benefits of Hunter Transmission Project remain.

Table 50 Relative market benefits of Hunter Transmission Project in *Step Change*

Class of market benefits	Relative market benefits (NPV, $ million)
Generator and storage capital deferral	1,289
Fixed operating and maintenance cost savings	409
Fuel cost savings	762
Variable operating and maintenance cost savings	52
Voluntary and involuntary load shedding reductions	759
Other network investment (REZ augmentations)	97
Gross market benefits excluding emissions	3,369
Emissions reduction benefits	415
Gross market benefits	3,784
Network (Actionable and Future ISP Projects)	-800
Total market benefits	2,984

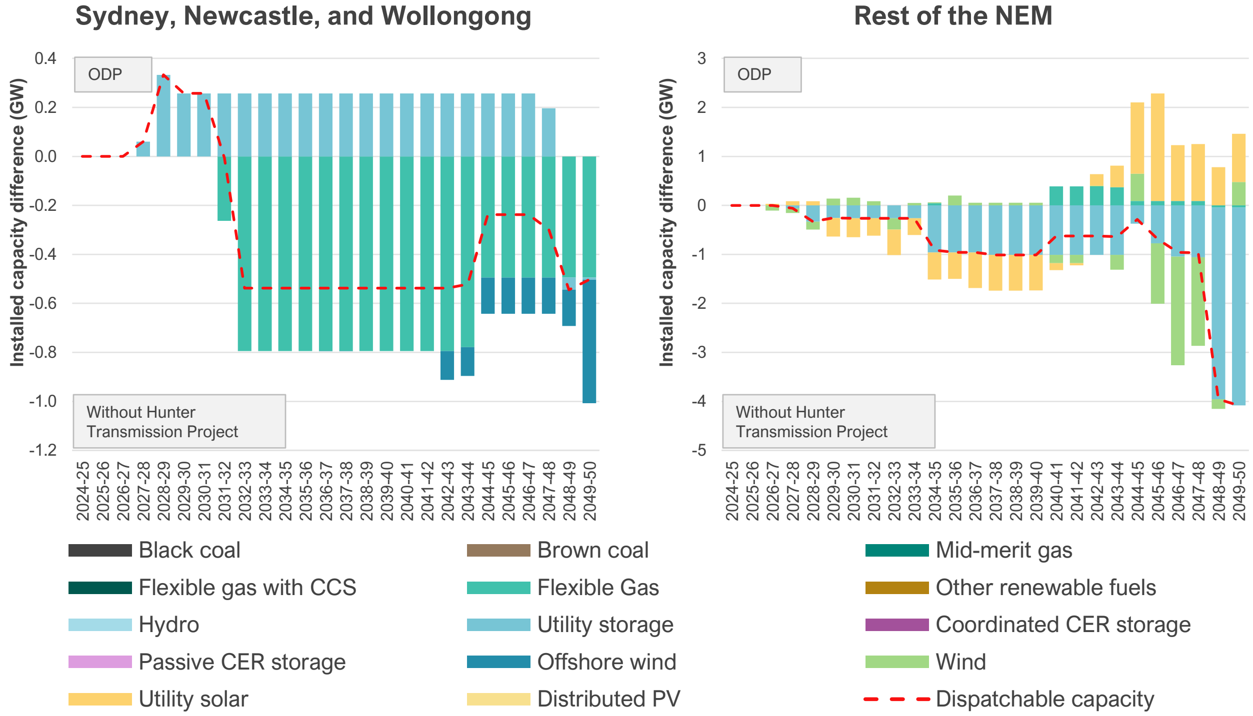
Figure 21 Annual relative market benefits of Hunter Transmission Project in *Step Change* (at 2028-29)



As Figure 22 shows, without Hunter Transmission Project, 800 MW of flexible gas is required by 2033-34 to support reliability in Sydney, Newcastle, and Wollongong. Furthermore, development of offshore wind in New South Wales would be needed in the late 2040's reaching 500 MW in 2049-50, to support the energy supply of the subregion.

In the rest of the NEM, by 2034-35, an additional 1.1 GW of utility storage is required in Central New South Wales and around 700 MW of additional utility solar in New South Wales and Victoria if Hunter Transmission Project was not to be delivered. Around 800 MW of utility wind capacity is also developed in Queensland by 2045-46. By 2048-49, the additional storage required in Central New South Wales increases to around 3.8 GW.

Figure 22 Comparison of capacity with and without Hunter Transmission Project in *Step Change* (at 2028-29)



Assessing the net market benefits of Hunter Transmission Project as an actionable project

The benefits and regrets associated with delaying the Hunter Transmission Project beyond its actionable window across all the scenarios are best demonstrated by comparing CDP3 with CDP4 (which is equivalent to CDP3 but with Hunter Transmission Project delayed to beyond its actionable window). Note that the least-cost DP for *Step Change* (CDP3) in the 2024 ISP includes two transmission projects that support supply to Sydney, Newcastle, Wollongong subregion – Hunter Transmission Project and Sydney Ring South. Hence, some of the benefits of Hunter Transmission Project that were assessed in the Draft 2024 ISP can also be delivered with an actionable Sydney Ring South.

Table 51 Comparing net market benefits between CDP3 and CDP4 ($ billion) – Hunter Transmission Project

	CDP3 – with actionable Hunter Transmission Project	CDP4 – without actionable Hunter Transmission Project	Change in net market benefits associated with not actioning the project[A]
Step Change	16.94	16.75	-0.19
Progressive Change	13.71	13.79	0.07
Green Energy Exports	58.35	58.03	-0.32
Weighted net market benefits	21.80	21.70	-0.10

	CDP3 – with actionable Hunter Transmission Project	CDP4 – without actionable Hunter Transmission Project	Change in net market benefits associated with not actioning the project[A]
Ranking weighted net market benefits	6	14	

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present

In *Step Change* and *Green Energy Exports*, an actionable Hunter Transmission Project increases net market benefits. In *Step Change,* the benefits arise from avoided storage and utility solar builds in New South Wales and in *Green Energy Exports*, the source of benefits are from avoided wind capacity investment in Northern New South Wales and Southern New South Wales that are otherwise not required (around 1.5 GW by 2034-35) and from avoided significant cost of demand side participation and fuel costs.

Finally, under *Progressive Change*, an actionable Hunter Transmission Project may be substituted with an actionable Sydney Ring South to meet Sydney, Newcastle, and Wollongong subregion's supply requirement. If Sydney Ring South were not delivered in its actionable window, then Hunter Transmission Project delivers $276 million in net market benefits in *Progressive Change*, mainly from avoided capital expenditure in the Sydney, Newcastle, and Wollongong subregion, see comparison of CDP5 and CDP6 in Table 52.

The augmentation delivers $99 million in weighted net market benefits. As with the TOOT, the impact of the nearly 5 GW of additional installed battery capacity across the NEM by 2029-30 (due to newly committed and anticipated projects and expanded Capacity Investment Scheme's dispatchable capacity), has reduced the relative value of the actionable project relative to the 2024 Draft ISP. For more information around development opportunities across scenarios, see Appendix 2.

The above comparisons, using CDP3 and CDP4, include an actionable Sydney Ring South. In *Progressive Change* this is earlier than what is least cost in that scenario. A comparison between CDP5 and CDP6 highlights the increase in net market benefits if Sydney Ring South were to be delayed. In this case and as seen in Table 52, the Hunter Transmission Project delivers greater net market benefits in all scenarios (including *Progressive Change*, where the Hunter Transmission Project would now deliver around $276 million in net market benefits). Overall, under this comparison, the project delivers around $251 million in weighted net market benefits.

The relative cost and benefits of an actionable Sydney Ring South project are discussed in the following subsection.

Table 52 Comparing net market benefits between CDP5 and CDP6 ($ billion) – Hunter Transmission Project with non-actionable Sydney Ring South

	CDP5 – with actionable Hunter Transmission Project and without actionable Sydney Ring South	CDP6 – without actionable Hunter Transmission Project and without actionable Sydney Ring South	Change in net market benefits associated with not actioning the project[A]
Step Change	16.96	16.75	-0.20
Progressive Change	13.84	13.56	-0.28
Green Energy Exports	58.08	57.76	-0.32
Weighted net market benefits	21.82	21.56	-0.25

	CDP5 – with actionable Hunter Transmission Project and without actionable Sydney Ring South	CDP6 – without actionable Hunter Transmission Project and without actionable Sydney Ring South	Change in net market benefits associated with not actioning the project[A]
Ranking weighted net market benefits	3	19	

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present

Assessing the regrets associated with Hunter Transmission Project as an actionable project

Table 53 below presents the weighted regrets across CDPs, and the change in weighted regrets associated with an actionable Hunter Transmission Project. The scenario driving the worst weighted regrets shifts from *Progressive Change* in CDP3 to *Green Energy Exports* in CDP4, showing the regret associated with under-investment as the scenario features earlier coal retirement and higher electricity demand which translates to earlier and greater need to support the major New South Wales load centre with new infrastructure.

Table 53 Weighted and worst weighted regrets of CDP3 and CDP4 ($ billion) – Hunter Transmission Project

	CDP3 – with actionable Hunter Transmission Project	CDP4 – without actionable Hunter Transmission Project	Change in weighted regrets associated with not actioning the project[A]
Step Change	0.01	0.09	0.08
Progressive Change	0.29	0.26	-0.03
Green Energy Exports	0.22	0.27	0.05
Worst weighted regrets	0.29	0.27	-0.02
Ranking based on worst weighted regrets	9	6	

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

Sydney Ring South

Sydney Ring South allows for increased power transfer into the major Sydney, Newcastle, and Wollongong load centre, similar to the Hunter Transmission Project, but from the southern part of New South Wales. Two Sydney Ring South options are identified as optimal in the forecast horizon in the 2024 ISP in at least one scenario.

Sydney Ring South Option 2d refers to a new switching station with modular power flow controllers. While it does not deliver increased transfer capacity, it improves power flow sharing between the northern and southern segments of the Central New South Wales to Sydney, Newcastle and Wollongong flow path, allowing for a relative increase in flows from southern New South Wales. This augmentation has an EISD of 2028-29, at a cost of $234 million.

Since the Draft 2024 ISP, Sydney Ring South Option 2d is found to be optimal in both *Step Change* and *Green Energy Exports* at 2029-30 and 2028-29, respectively.

Sydney Ring Option 2b also improves transfer capacity to Sydney, Newcastle and Wollongong, by 700 MW. It is developed in *Green Energy Exports* in 2039-40 (after its actionable window considering its EISD of 2030-31) at a cost of $1,021 million. This option is not developed in the other scenarios at any timing, therefore is not further assessed in the cost-benefit analysis.

This subsection discusses the case for Sydney Ring South, by first assessing the relative market benefits of the project via TOOT analysis. It then considers the relative merits of including the project by considering its weighted net market benefits when removed from CDP14.

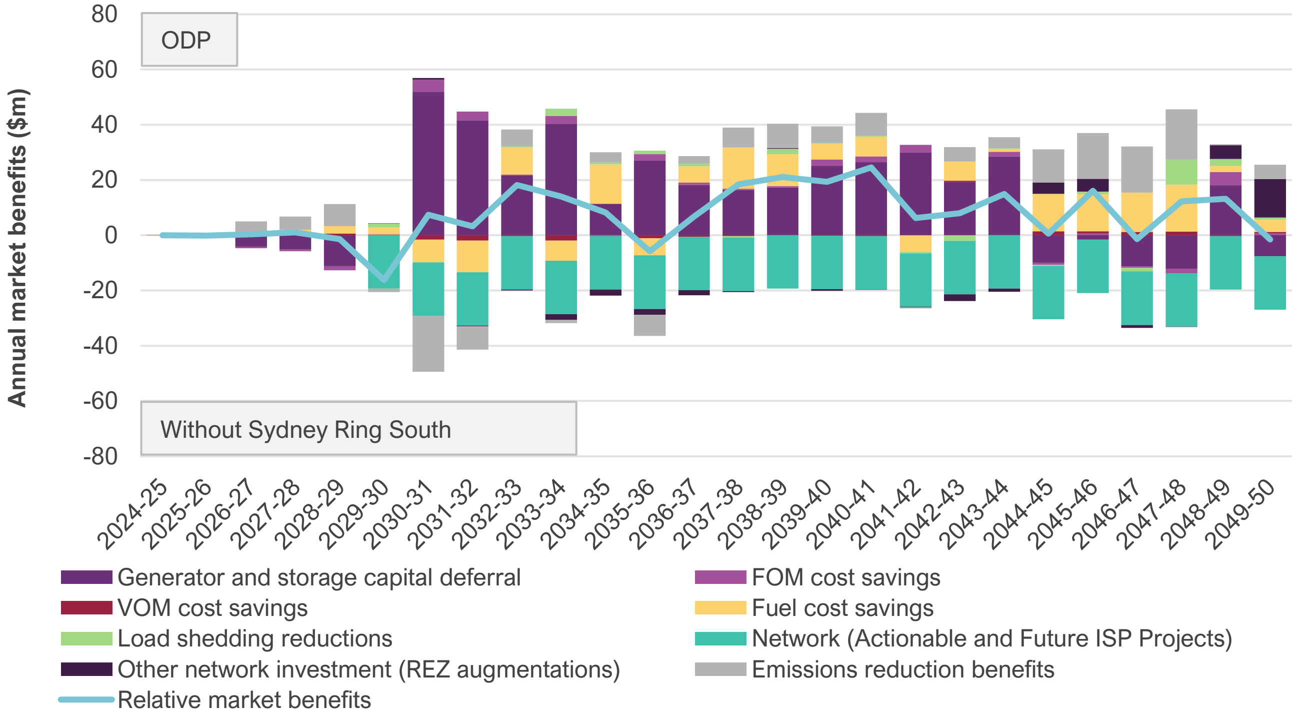
Assessing the relative market benefits of Sydney Ring South via TOOT analysis

As Table 54 highlights, Sydney Ring South delivers around $58 million in relative market benefits over the outlook period in *Step Change*. The majority of these benefits come from capital deferral of approximately 200 MW of deep storage in Northern New South Wales from 2030-31.

Table 54 Relative market benefits of Sydney Ring South in *Step Change*

Class of market benefits	Relative market benefits (NPV, $ million)
Generator and storage capital deferral	136
Fixed operating and maintenance cost savings	10
Fuel cost savings	24
Variable operating and maintenance cost savings	-2
Voluntary and involuntary load shedding reductions	18
Other network investment (REZ augmentations)	4
Gross market benefits excluding emissions	190
Emissions reduction benefits	13
Gross market benefits	203
Network (Actionable and Future ISP Projects)	-145
Total market benefits	58

Figure 23 Annual relative market benefits of Sydney Ring South in *Step Change* (at 2029-30)



Assessing the net market benefits of Sydney Ring South as an actionable project

The benefits and regrets associated with delaying the Sydney Ring South augmentation can be assessed by comparing CDP14 with CDP21 (which is equivalent to CDP14, but with Sydney Ring South Option 2d delayed to after its actionable window).

Table 55 Comparing net market benefits between CDP14 and CDP21 ($ billion) – Sydney Ring South

	CDP14 – with actionable Sydney Ring South	CDP21 – without actionable Sydney Ring South	Change in net market benefits associated with not actioning the project[A]
Step Change	16.66	16.67	0.01
Progressive Change	13.64	13.68	0.04
Green Energy Exports	59.60	59.27	-0.33
Weighted net market benefits	21.83	21.80	-0.03
Ranking weighted net market benefits	1	5	

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

As Table 55 above highlights, the net market benefits of an actionable Sydney Ring South are positive in *Green Energy Exports* by $331 million, and marginally negative in *Progressive Change* and in *Step Change* (around negative $35 million and $13 million respectively). On a weighted net market benefits basis, the project would marginally increase net market benefits by $29 million if delivered at an actionable timing.

In *Green Energy Exports*, the main source of benefits comes from avoided fuel costs and generator and storage capital costs associated with an actionable project.

The relative market benefits of delivering Sydney Ring South at actionable timings improve under the *Extended Eraring* sensitivity and the *Additional Load* sensitivity, discussed in A6.8 reflecting the need for timely augmentation into the Sydney, Newcastle and Wollongong subregion to supply potential new loads.

Given the recent agreement to extend the Eraring Power Station, the sensitivity provides an important consideration. With Eraring extended by two years, the augmentation provides $38 million in benefits (comparing CDP14 and CDP21). Stakeholders also suggested that the industrial and commercial load growth in New South Wales is plausible to exceed the forecast within *Step Change* (see A6.8.3 for more details). With additional load growth, the augmentation provides $33 million in benefits (comparing CDP14 and CDP21). Given the timing of Eraring Power Station's closure, and given the plausible case for additional load growth, AEMO considers the case for actioning the augmentation is stronger than is presented in the scenario analysis, and concludes that the project is an Actionable ISP Project.

Assessing the regrets associated with Sydney Ring South as an actionable project

Table 56 shows the change in worst weighted regrets associated with the removal of Sydney Ring South from CDP14 (which has an actionable Project Marinus Stage 2). Worst weighted regrets increase by around $15 million when the project is set at an actionable timing. The expected improvement in weighted net market benefits exceed the potential worst weighted regret when the project is actionable.

Table 56 Weighted and worst weighted regrets of CDP14 and CDP21 ($ billion) – Sydney Ring South

	CDP14 – with actionable Sydney Ring South	CDP21 – without actionable Sydney Ring South	Change in weighted regrets associated with not actioning the project[A]
Step Change	0.13	0.12	-0.01
Progressive Change	0.32	0.30	-0.01
Green Energy Exports	0.03	0.08	0.05
Worst weighted regrets	0.32	0.30	-0.01
Ranking based on worst weighted regrets	13	11	

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

Queensland – New South Wales Interconnector (QNI Connect)

QNI Connect increases transfer capacity between New South Wales and Queensland. QNI Connect Option 2 provides an increase of 1,260 MW from New South Wales to Queensland and 1,700 MW in the reverse direction towards New South Wales. This project has not been declared as actionable in previous ISPs and therefore has only a two-year actionable window. With an EISD of 2033-34, the project may therefore be declared as actionable if optimal before 2034-35. At 2034-35, this project costs $2.8 billion.

This augmentation would support Queensland following a number of coal closures – in both *Step Change* and *Green Energy Exports,* all Queensland coal generators are forecast to have retired by 2034-35. It also allows for higher levels of sharing of renewable resources between Queensland and New South Wales.

The project is found at an actionable timing of 2034-35 in *Step Change* and *Green Energy Exports* but is found to be optimal in *Progressive Change* if delivered in 2039-40.

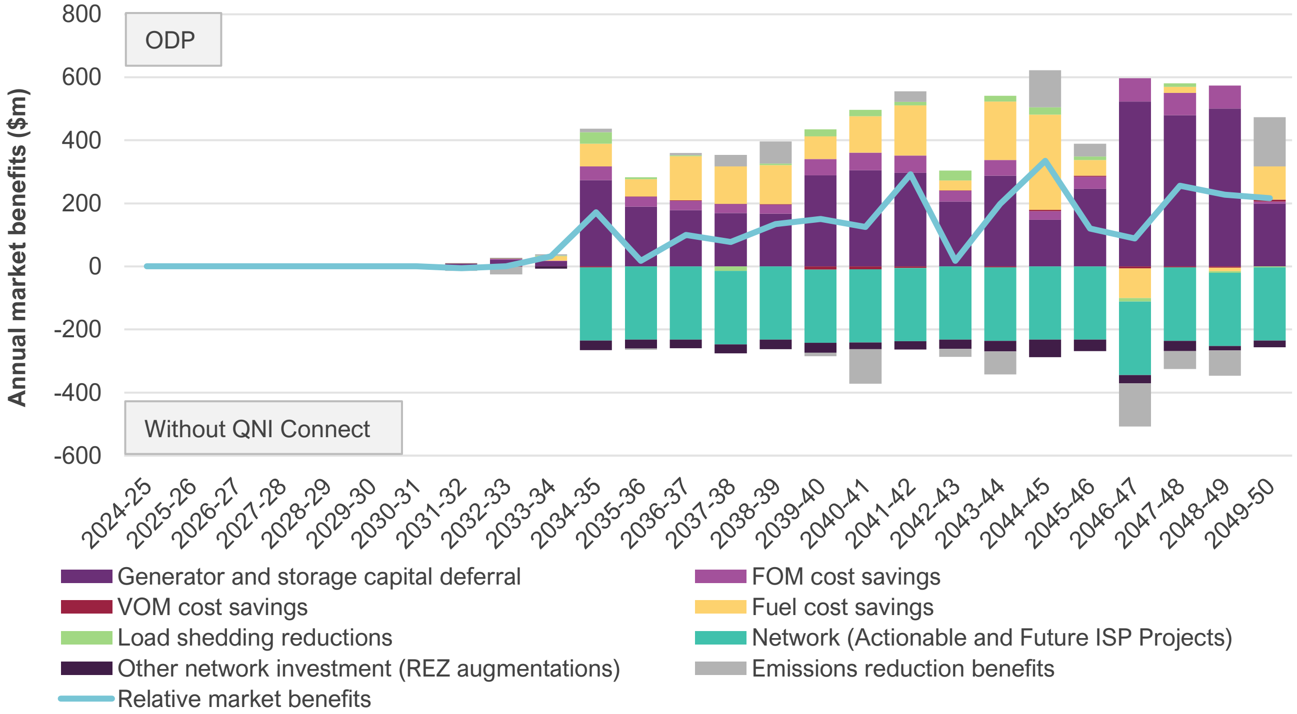
Assessing the relative market benefits of QNI Connect in *Step Change* via TOOT analysis

The benefits associated with this augmentation are presented in Table 57 and Figure 24 for *Step Chan*ge. The main source of relative market benefits are avoided generator and storage capital costs, fuel cost savings, and fixed operating and maintenance cost savings. The augmentation delivers around $751 million in net market benefits.

Table 57 Relative market benefits of QNI Connect in *Step Change*

Class of market benefits	Relative market benefits (NPV, $ million)
Generator and storage capital deferral	1,268
Fixed operating and maintenance cost savings	197
Fuel cost savings	485
Variable operating and maintenance cost savings	-7
Voluntary and involuntary load shedding reductions	59
Other network investment (REZ augmentations)	-140
Gross market benefits excluding emissions	1,863
Emissions reduction benefits	-1
Gross market benefits	1,862
Network (Actionable and Future ISP Projects)	-1,111
Total market benefits	751

Figure 24 Annual relative market benefits of QNI Connect in *Step Change* (QNI Connect in 2034-35)



Assessing the net market benefits of QNI Connect as an actionable project

Table 58 presents the difference in net market benefits between CDP3 and CDP22 (which is similar to CDP3 but with QNI Connect being delivered after its actionable window).

The project increases net market benefits in *Step Change and Green Energy Exports* by approximately $282 million and $1.17 billion respectively, while decreasing the net market benefits in *Progressive Change* by $244 million. Overall, delivering the project within its actionable window would result in increased weighted net market benefits of around $194 million relative to a delay.

Table 58 Comparing net market benefits between CDP3 and CDP22 ($ billion) – QNI Connect

	CDP3 – with actionable QNI Connect	CDP22– without actionable QNI Connect	Change in net market benefits associated with not actioning the project[A]
Step Change	16.94	16.66	-0.28
Progressive Change	13.71	13.96	0.24
Green Energy Exports	58.35	57.18	-1.17
Weighted net market benefits	21.80	21.60	-0.19
Ranking weighted net market benefits	6	17	

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

In *Green Energy Exports*, the main source of benefits associated with delivering the project within its actionable window is deferral of around 1.6 GW of storage and 2.1 GW of solar capacity in Queensland while enabling higher wind builds in New South Wales.

In *Step Change*, QNI Connect avoids significant solar and storage capacity in 2034-35 (1 GW and 800 MW respectively) in Queensland and New South Wales but leads to around 800 MW of wind capacity to be developed in Queensland, improving the resource diversity of the NEM renewable energy portfolio.

Assessing the regrets associated with QNI Connect as an actionable project

Table 59 below presents the weighted regrets across the scenarios for CDP3 and CDP22.

The worst weighted regrets for CDP22 are driven by the risks associated with under-investment in *Green Energy Exports* relative to the least-cost DP for that scenario. Weighted regrets range from $126 million to $397 million. The project increases worst weighted regrets by around $110 million. Overall, CDP22 is ranked 18th best for worst weighted regrets.

Table 59 Weighted and worst weighted regrets of CDP3 and CDP22 ($ billion) – QNI Connect

	CDP3 – with actionable QNI Connect	CDP22 – without actionable QNI Connect	Change in weighted regrets associated with actioning the project[A]
Step Change	0.01	0.13	0.12
Progressive Change	0.29	0.18	-0.10
Green Energy Exports	0.22	0.40	0.18
Worst weighted regrets	0.29	0.40	0.11
Ranking based on worst weighted regrets	9	18	

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

Queensland SuperGrid South

This augmentation is a key component of the Queensland SuperGrid Infrastructure Blueprint, and proposes to deliver an increase in network capacity of 3,150 MW between Central Queensland and Southern Queensland in both directions. It has an EISD of 2031-32, a year later than assumed in the Draft 2024 ISP as informed by the project proponent.

As the project has not been identified in previous ISPs, the actionable window is only two years. Benefits from this augmentation (Queensland SuperGrid South Option 5) stem from being able to improve access to the anticipated Borumba Dam pumped hydro project as well as allowing greater energy and capacity sharing between southern and central Queensland.

It is optimal at an actionable timing in the least-cost DPs for *Step Change* (in 2031-32) and *Green Energy Exports* (in 2032-33) but not in *Progressive Change* (where its delivery is found optimal slightly later in 2034-35).

Assessing the relative market benefits of Queensland SuperGrid South in *Step Change* via TOOT analysis

The benefits provided by Queensland SuperGrid South in *Step Change* are presented in Table 60 and Figure 25. Benefits are primarily due to deferred capital costs, as there is a need for additional utility storage, from the mid-2030s without the augmentation (primarily in Queensland). Queensland SuperGrid South contributes approximately $2.2 billion of benefits in the *Step Change* scenario. The relative market benefits of Queensland SuperGrid South remain relatively unchanged compared to the 2024 Draft ISP.

Developing Queensland SuperGrid South in *Step Change* would avoid the need to build around 1.9 GW of utility storage in Queensland by 2034-35, avoids additional capacity requirement in southern regions in later years, and allows for more effective utilisation of central Queensland capacity in later years to support demand growth, see Figure 26.

Table 60 Relative market benefits of Queensland SuperGrid South in *Step Change*

Class of market benefits	Relative market benefits (NPV, $ million)
Generator and storage capital deferral	3,123
Fixed operating and maintenance cost savings	351
Fuel cost savings	387
Variable operating and maintenance cost savings	22
Voluntary and involuntary load shedding reductions	71
Other network investment (REZ augmentations)	-27
Gross market benefits excluding emissions	3,928
Emissions reduction benefits	133
Gross market benefits	4,060
Network (Actionable and Future ISP Projects)	-1,871
Total market benefits	2,190

Figure 25 Annual relative market benefits of Queensland SuperGrid South in *Step Change* (at 2031-32)

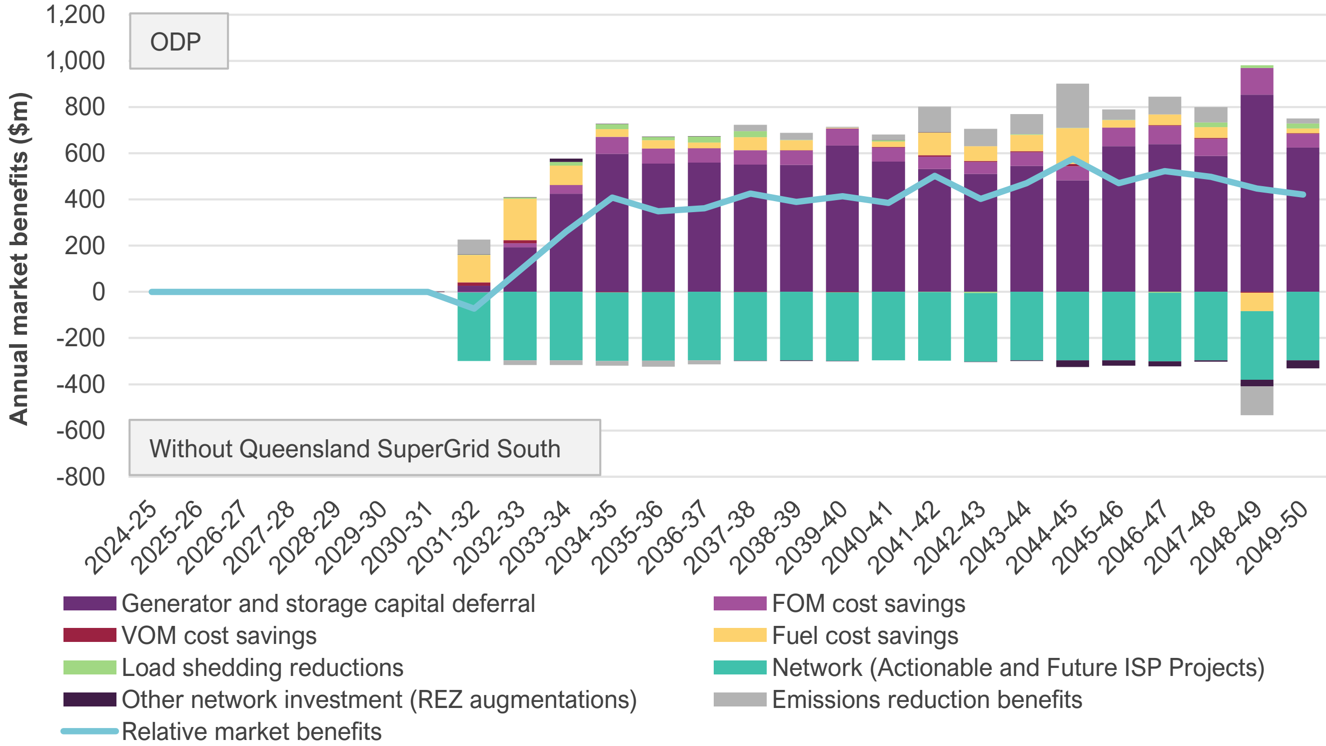
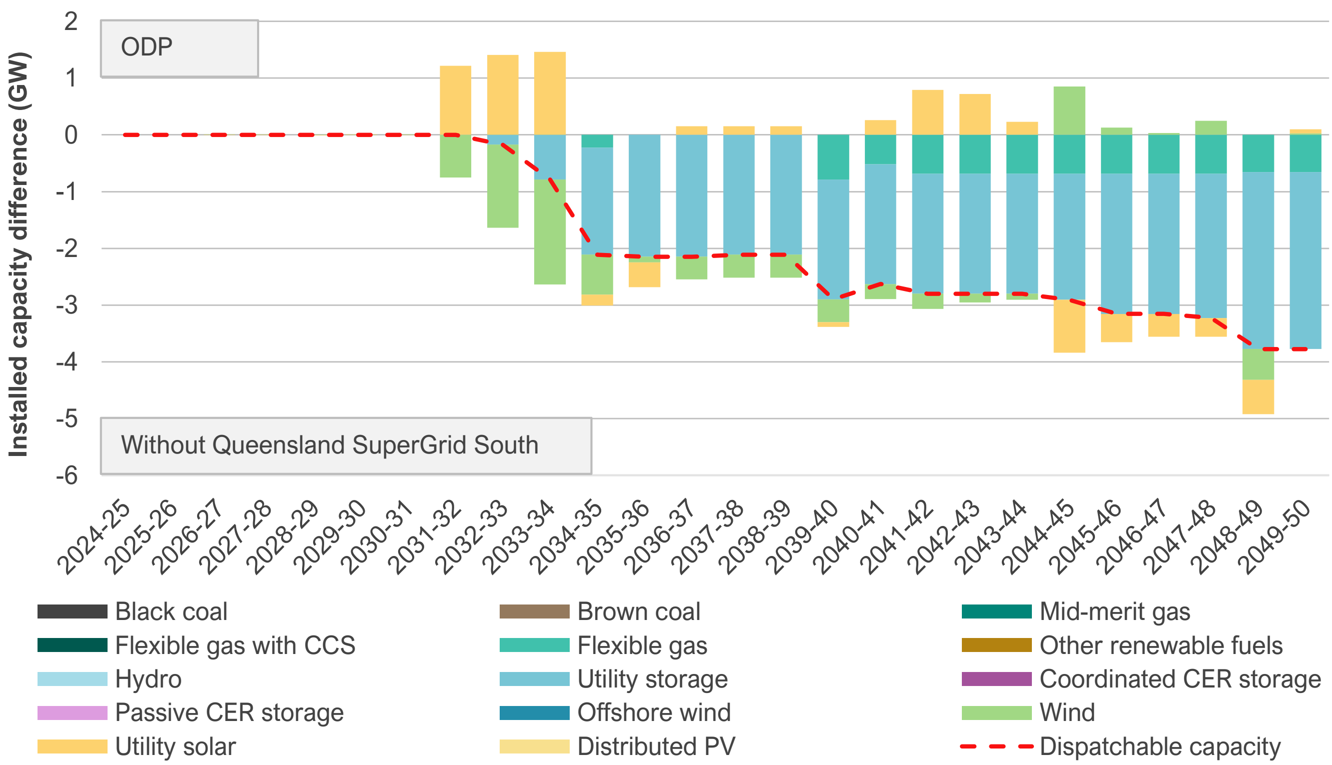


Figure 26 Comparison of generation capacity with and without Queensland SuperGrid South in *Step Change* (at 2031-32)



Assessing the net market benefits of Queensland SuperGrid South as an actionable project

The benefits of actioning Queensland SuperGrid South can be derived by comparing CDP14 (the least-cost DP for *Step Change* with an actionable Project Marinus Link Stage 2) and CDP24, which is equivalent to CDP14 but delays the Queensland SuperGrid South project until after its actionable window (a delay of only two years).

As seen in Table 61, Queensland SuperGrid South provides an increase in weighted net market benefits of $15 million if delivered within its actionable window, justifying its consideration as an actionable project. An actionable augmentation delivers $48 million in net market benefits in *Step Change* and $191 million in *Green Energy Exports* but increases costs in *Progressive Change* by $83 million.

This represents a subtle difference to the Draft 2024 ISP, where an actionable project delivered benefits in *Green Energy Exports* (of around $200 million) and resulted in an increase in benefits of $100 million in *Progressive Change*. Net market benefits in *Step Change* have also reduced since the Draft 2024 ISP.

Table 61 Comparing net market benefits between CDP14 and CDP24 ($ billion) – Queensland SuperGrid South

	CDP14 – with actionable Queensland SuperGrid South	CDP24 – without actionable Queensland SuperGrid South	Change in net market benefits associated with not actioning the project[A]
Step Change	16.66	16.61	-0.05
Progressive Change	13.64	13.73	0.08
Green Energy Exports	59.60	59.41	-0.19
Weighted net market benefits	21.83	21.82	-0.01
Ranking weighted net market benefits	1	2	

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

As discussed, Queensland SuperGrid South is a key network asset that will ensure its effective utilisation to support Queensland's energy transition, as outlined in the Queensland Energy and Jobs Plan. The benefits of actioning the project have decreased since the Draft 2024 ISP, primarily due to the progression of additional battery storage projects as identified in the February 2024 Generation Information update, and further dispatchable capacity that is developed in Queensland in this ISP with the expanded CIS. However, the deep storage that Borumba Dam will provide increases the system's resilience to uncertain and unpredictable weather patterns, and will be a key enabler for the closure of coal power stations in that region. As such, AEMO considers that despite relatively low net market benefits for the project, that it is appropriate to action the investment as it both provides positive weighted net market benefits if delivered within its actionable window, and that it will improve the resilience of the power system if other weather patterns emerge than those modelled to identify the net market benefits.

In *Step Change*, with improved access to the anticipated Borumba Dam Pumped Hydro, the augmentation reduces coal and gas generation in Queensland, and avoids increased wind builds mainly in Central Queensland.

Assessing the regrets associated with Queensland SuperGrid South as an actionable project

Table 62 below presents the weighted regrets across the scenarios for CDP14 and CDP24. It shows that delivering the project shortly after its actionable window increases regrets in *Step Change,* and the reduction in regrets associated with not actioning the project in *Green Energy Exports* and *Progressive Change* are relatively small.

Table 62 Weighted and worst weighted regrets of CDP14 and CDP24 ($ billion) – Queensland SuperGrid South

	CDP14 – with actionable Queensland SuperGrid South	CDP24 – without actionable Queensland SuperGrid South	Change in weighted regrets associated with not actioning the project[A]
Step Change	0.13	0.15	0.02
Progressive Change	0.32	0.28	-0.04
Green Energy Exports	0.03	0.06	0.03
Worst weighted regrets	0.32	0.28	-0.04
Ranking based on worst weighted regrets	13	8	

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

Gladstone Grid Reinforcement

This augmentation is optimal if delivered within its actionable window in *Step Change* and *Green Energy Exports*. Its benefits arise as a result of supplying the Gladstone subregion as coal generation retires.

Assessing the relative market benefits of Gladstone Grid Reinforcement and Queensland SuperGrid South in *Step Change* via TOOT analysis

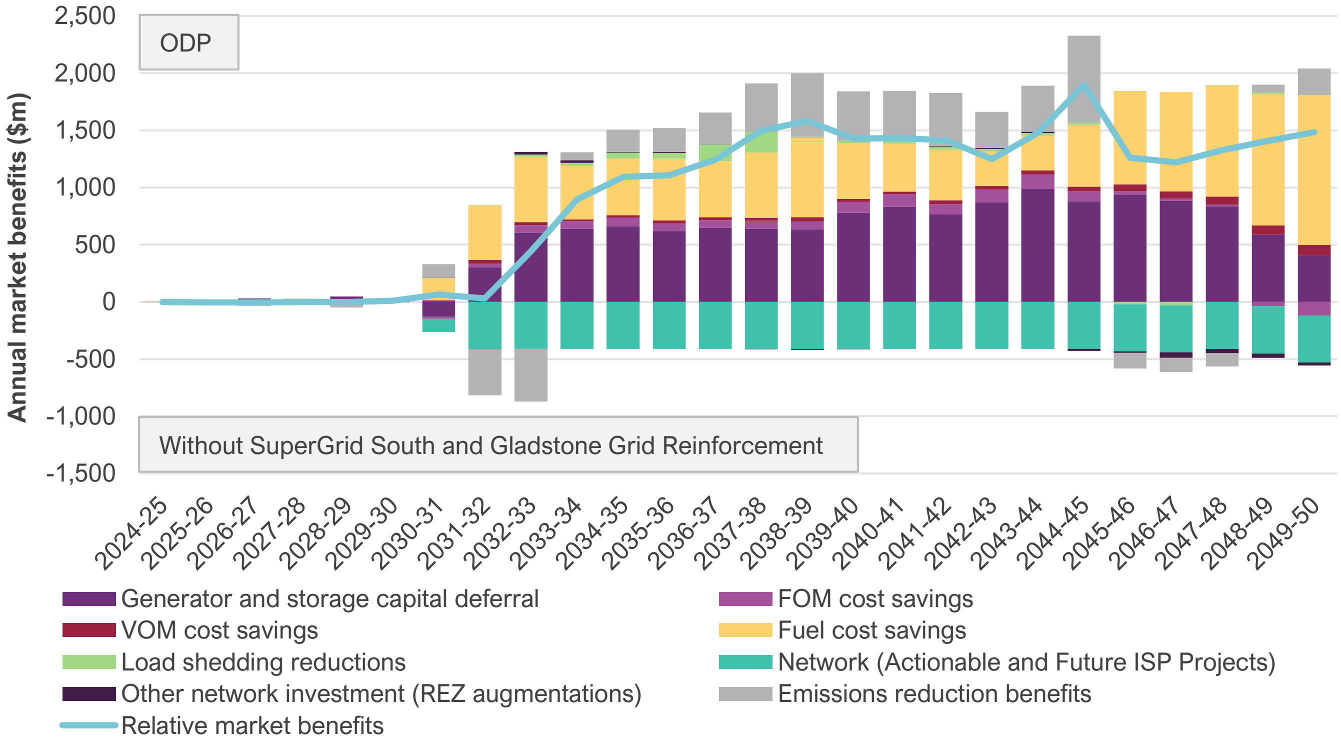
As this augmentation option is a pre-requisite to the development of Queensland SuperGrid South Option 5, benefits are linked to the delivery of both projects.

The benefits associated with these augmentations are presented in Table 63 and Figure 27 for *Step Change*. These augmentations deliver net market benefits coming from avoided generator and storage capital, and fuel cost savings in Gladstone Grid. Together, the augmentations contribute approximately $7.2 billion in net market benefits to the ODP in *Step Change*. AEMO has considered it inappropriate to conduct a TOOT of this project alone given the interaction between the two augmentations, however considering the relative net market benefits of Queensland SuperGrid South discussed above (identified above as approximately $2.2 billion), the majority therefore of these combined project benefits may be attributable to Gladstone Grid Reinforcement, recognising its critical support for the industrial precinct and supporting the region’s transformation following coal closure.

Table 63 Relative market benefits of Gladstone Grid Reinforcement and Queensland SuperGrid South in *Step Change*

Class of market benefits	Relative market benefits (NPV, $ million)
Generator and storage capital deferral	4,222
Fixed operating and maintenance cost savings	340
Fuel cost savings	3,938
Variable operating and maintenance cost savings	239
Voluntary and involuntary load shedding reductions	235
Other network investment (REZ augmentations)	-8
Gross market benefits excluding emissions	8,967
Emissions reduction benefits	941
Gross market benefits	9,907
Network (Actionable and Future ISP Projects)	-2,667
Total market benefits	7,240

Figure 27 Annual relative market benefits of Queensland SuperGrid South and Gladstone Grid Reinforcement in *Step Change* (Queensland SuperGrid South at 2031-32, and Gladstone Grid Reinforcement in 2030-31)



Assessing the net market benefits of Gladstone Grid Reinforcement and Queensland SuperGrid South as actionable projects

Table 64 presents the change in net market benefits of CDP3 and CDP19 (which is similar to CDP3 but delivers both Queensland SuperGrid South and Gladstone Grid Reinforcement after their respective actionable windows).

Both projects deliver increases in net market benefits in *Step Change and Green Energy Exports* (amounting to around $55 million and $1.1 billion), while increasing the system cost in *Progressive Change* by $307 million. Overall, delaying both projects result in a reduction in weighted net market benefits of around $57 million.

While not presented below, a comparison of CDP18 and CDP19 shows that delaying Gladstone Grid Reinforcement beyond its actionable window (when Queensland SuperGrid South is delivered beyond its own actionable window) sees a reduction in weighted net market benefits of around $67 million.

Overall, CDP19 is ranked around the middle of the CDP collection – 10th best in weighted net market benefits.

Table 64 Comparing net market benefits between CDP3 and CDP19($ billion) – Queensland SuperGrid South and Gladstone Grid Reinforcement

	CDP3 – with actionable Queensland SuperGrid South and Gladstone Grid Reinforcement	CDP19 – without actionable Queensland SuperGrid South and Gladstone Grid Reinforcement	Change in net market benefits associated with not actioning the project[A]
Step Change	16.94	16.89	-0.06
Progressive Change	13.71	14.02	0.31
Green Energy Exports	58.35	57.27	-1.08
Weighted net market benefits	21.80	21.74	-0.06
Ranking based on weighted net market benefits	6	10	

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

In *Green Energy Exports*, the main source of benefit associated with delivering these projects within their actionable windows is deferred capacity and fuel cost savings from avoided flexible gas in the Gladstone subregion to support the load growth that is forecast in that scenario. The Gladstone Grid Reinforcement avoids around 500 MW of additional flexible gas by 2030-31 in the Gladstone Grid subregion, which is not required if the augmentation is delivered in that year instead.

In *Progressive Change*, delivering these two augmentations in their actionable windows avoids coal and gas generation in Queensland and New South Wales in 2030-31 and 2031-32 with a corresponding increase in emissions reduction benefits.

Assessing the regrets associated with Gladstone Grid Reinforcement and Queensland SuperGrid South as actionable projects

Table 65 below presents the weighted regrets across the scenarios for CDP3 and CDP19.

The worst weighted regrets for CDP19 are driven by the risks associated with under-investment in *Green Energy Exports* relative to what the least-cost DP for that scenario develops. Weighted regrets range from $29 million in *Step Change* to $384 million in *Green Energy Exports*. Overall, CDP19 is ranked 17th best for worst weighted regrets.

Table 65 Weighted and worst weighted regrets of CDP3 and CDP19 ($ billion) – Queensland SuperGrid South and Gladstone Grid Reinforcement

	CDP3 – with actionable Queensland SuperGrid South and Gladstone Grid Reinforcement	CDP19 – without actionable Queensland SuperGrid South and Gladstone Grid Reinforcement	Change in weighted regrets associated with actioning the project[A]
Step Change	0.01	0.03	0.02
Progressive Change	0.29	0.16	-0.13
Green Energy Exports	0.22	0.38	0.16
Worst weighted regrets	0.29	0.38	0.10
Ranking based on worst weighted regrets	9	17	

A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

A6.6.3 Summarising the benefits of a coordinated approach to transmission development

Table 66 presents a comparison of the weighted net market benefits of CDP3, which is the least-cost DP under the most-likely *Step Change* scenario, CDP14, which has the highest weighted net market benefits, compared with CDP25, which has no projects that are developed within their actionable windows, in all scenarios.

Table 66 Determining the benefits of a coordinated approach to transmission development ($ billion)

CDP	*Step Change*	*Progressive Change*	*Green Energy Exports*	Weighted net market benefits
CDP3: Least-cost *Step Change*	16.94	13.71	58.35	21.80
CDP14: Least-cost *Step Change* with actionable Project Marinus Stage 2	16.66	13.64	59.60	21.83
CDP25: No actionable projects	11.78	12.10	45.05	16.91
Net market benefits of CDP14 due to actionability of projects	4.87	1.54	14.55	4.92

The weighted net market benefits delivered by the transmission projects within their actionable windows relative to CDP25 amounts to $4.92 billion. This is higher than in the 2022 ISP, where it amounted to $400 million. There are several reasons for this, including:

- Recognition that projects that are already in-flight (for example, the previously identified actionable projects from the 2022 ISP) will lose momentum if they were deferred to later delivery timings. This leads potentially to a longer gap between an actionable timing and the timeframe they would be able to be deliverable to if they were not actioned. If deferred, the absence of these timely developments often lead to greater impact on the NEM's alternative generation and storage developments, and therefore the investment costs that would be incurred with these alternate timings (as consulted upon with stakeholders in the *ISP Methodology*).
- Applying a rising cost for transmission projects (in real dollars) over the outlook period increases the relative cost for delayed delivery of these projects (as consulted upon with stakeholders in the 2023 *Transmission Expansion Options Report*), compared to the cost of delay previously when cost escalation outside of economy-wide inflation was not included (as per the 2022 ISP).

- The inclusion of the emissions reduction as a class of market benefits, with transmission developments enabling greater reduction in emissions outcomes in some scenarios.

These benefits are also around $1.7 billion higher than those found in the Draft 2024 ISP. This is due to a number of reasons including:

- The inclusion of the emissions reduction as a class of market benefits.
- Higher levels of generator and storage capital expenditure being deferred due to the impact of having more actionable projects.

Later EISDs for several projects.

A6.7 Step 6A: Selecting the optimal development path

This section outlines the process and insights associated with selecting the ODP. The resilience of the ODP selection to alternative sensitivities is discussed in Section A6.8.

Table 67 presents the top six CDPs from the scenario collection using the risk-neutral weighted net market benefits method, and the risk-averse worst weighted regrets method. The differences in transmission augmentations across these CDPs are provided in Table 68.

Table 67 Top six candidate development paths across scenarios (in $ billion) – in order of descending weighted net market benefits

CDP	*Step Change*	*Progressive Change*	*Green Energy Exports*	WNMB	WNMB Rank	Worst weighted regrets	WWR Rank
14	16.66	13.64	59.60	21.83	1	0.32	13
24	16.61	13.73	59.41	21.82	2	0.28	8
5	16.96	13.84	58.08	21.82	3	0.26	4
18	16.91	13.79	58.31	21.81	4	0.26	2
21	16.67	13.68	59.27	21.80	5	0.30	11
3	16.94	13.71	58.35	21.80	6	0.29	8

Table 68 Potential actionable projects in the top six CDPs

In these CDPs …		…These projects would be actionable:													
		Gladstone Grid Reinforcement	Queensland SuperGrid South	QNI Connect	New England REZ Network Infrastructure Project	New England REZ Extension	Hunter Transmission Project	Sydney Ring South	HumeLink	VNI West	Project Marinus Stage 1	Project Marinus Stage 2	Waddamana to Palmerston transfer capability upgrade	Mid North South Australia REZ Expansion	Hunter-Central Coast REZ Network Infrastructure Project
14	CDP3 with actionable Marinus Link Stage 2	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
24	CDP14 without actionable Queensland SuperGrid South	✓		✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
5	CDP3 without actionable Sydney Ring South	✓	✓	✓	✓	✓	✓		✓	✓	✓		✓	✓	✓
18	CDP3 without actionable Queensland SuperGrid South	✓		✓	✓	✓	✓	✓	✓	✓	✓		✓	✓	✓
21	CDP14 without actionable Sydney Ring South	✓	✓	✓	✓	✓	✓		✓	✓	✓	✓	✓	✓	✓
3	*Step Change* least-cost DP	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓	✓	✓

Selecting the ODP from this collection requires consideration of both the weighted net market benefits and worst weighted regrets for each CDP against each other, and the resilience of each CDP to changes in key assumptions as identified in sensitivity analyses. Prior to that evaluation, a shortlist of CDPs is selected for consideration by comparing the potential trade-offs between weighted net market benefits and worst weighted regrets.

CDP14 is the top CDP in terms of weighted net market benefits, although it is not as near to the top of the CDP collection in terms of worst weighted regrets. This set of actionable projects facilitates the efficient connection and sharing of VRE across the NEM to support retirement of coal, forecast growth in electricity demand, and the energy policies considered in this 2024 ISP. The regrets for CDP14 are mostly associated with the risks of over-investing under the *Progressive Change* scenario, where risks of industrial load closures and lower demand growth more broadly reduces the value of earlier transmission developments.

Unlike in the Draft 2024 ISP where the greatest driver of regret was under-investment, the worst weighted regrets across most CDPs are now driven by the potential regret in *Progressive Change*. With some exceptions, CDPs that have fewer actionable projects relative to CDP3 tend to rank higher in worst weighted regrets. In particular, delaying Queensland transmission projects (SuperGrid South, Gladstone Grid Reinforcement, or QNI Connect) in *Progressive Change* has the most significant impact on reducing potential regrets associated with over-investment relative to CDP3. On the other hand, CDPs that have more actionable projects than CDP3 such as CDP14 tend to be ranked worse.

Some of the Queensland projects (in particular Gladstone Grid Reinforcement and to a lesser extent QNI Connect) deliver clear benefits on a weighted net market benefits basis. As a result, AEMO has carefully considered the degree to which worst weighted regret rankings should influence selecting the ODP.

On weighted net market benefits basis, CDP14 is followed by CDP24 which is the same collection of potentially actionable projects but does not feature an actionable Queensland SuperGrid South, a project that is a key enabler for the transition in Queensland, as described earlier.

CDP5 does not feature an actionable Sydney Ring South compared to CDP3. The benefits of Sydney Ring South come from being able to supply the Sydney, Newcastle, Wollongong subregion from the south by complementing the transfer capacity increase provided by the Hunter Transmission Project. Worst weighted regrets of this CDP come from the risk of under-investment in *Green Energy Exports*.

CDP18 follows, reducing weighted net market benefits by a further $8 million. CDP18 does not feature an actionable Queensland SuperGrid South compared to CDP3. Compared to CDP24 and CDP14, CDP18 and CDP3 does not feature Project Marinus Stage 2 within its actionable window, and their net market benefits in *Green Energy Exports* are much lower as a result. This CDP ranks second best in worst weighted regrets, which represents the risk of over investment in *Progressive Change*.

CDP21, which does not have Sydney Ring South as an actionable project compared to CDP14, follows. It results in a further reduction in net market benefits of around $5 million from CDP18. This CDP is mid-ranked in worst weighted regret at rank 11th.

The least-cost DP in *Step Change,* CDP3, comes sixth in weighted net market benefits basis, being worse off by approximately $35 million than the top-ranked CDP (CDP14). CDP3 is mid-ranked on a worst weighted regret basis at ninth.

It is important to consider the potential improved resilience that key CDPs may provide to alternative assumptions affecting the future conditions that the NEM may face. This 2024 ISP explores this by conducting additional sensitivity analysis performed against the shortlist presented above, with greatest focus on CDP14, CDP24, CDP5, CDP18, CDP21, and CDP3. These are the highest-ranked CDPs in terms of weighted net market benefits and some are highly ranked in terms of worst weighted regrets.

Because it has the highest weighted net market benefits, AEMO considers CDP14 to be the most appropriate candidate to be the Optimal Development Path, subject to the assessment below. Section A6.8 discusses the robustness of the CBA collection, then Section A6.11 presents a final assessment of the candidates and the ODP.

Section A6.9 below further examines whether an alternative CDP would help to align with consumer risk preferences, and it also provides more insights on distributional effects.

A6.8 Step 6B: Testing the resilience of the candidate development paths

This section outlines the resilience of the CDPs' identified market benefits to changes in input assumptions used in the core scenarios. While more CDPs are explored in the sensitivities, the discussion in this sub-section focuses on the seven CDPs with the highest weighted net market benefits, unless otherwise stated, to allow for further consideration of additional insights to assist the identification of the ODP.

Additional sensitivity analyses have been included, extending the analysis provided in the Draft 2024 ISP to additional risks highlighted by stakeholders on the Draft 2024 ISP consultation, and other recent developments.

The impact of these sensitivities on generation and storage capacity development is explored in depth in Appendix 2. Scenario and sensitivity analysis capacity developments, cost-benefit and emissions outcomes are also provided in the Generation and Storage Outlook Workbooks[47].

Since the Draft 2024 ISP, additional analysis has been performed to demonstrate:

- The impact on the ODP of the agreement to extend the operating life of the Eraring Power Station.
- The value of the forecast coordination of CER.
- The impact on the ODP if additional industrial demand in addition to the growth forecast in the *Step Change* scenario connects to key growth areas, particularly northern South Australia and Sydney, Newcastle and Wollongong.
- The impact on the ODP of updated assumptions regarding the electrification pace of the transport industry.
- The impact on the ODP if supply chains are constrained, slowing the capability to commission generation, storage and transmission developments.
- The impact on the ODP if hydrogen production was less flexible than assumed in the scenario analysis.
- The impact on the ODP if weather variance is different to the core sequence of weather applied in the scenario analysis.

A6.8.1 *Extended Eraring* sensitivity

The *Extended Eraring* sensitivity evaluates the impact of the agreement between Origin Energy and the New South Wales Government to extend the operation of Eraring Power Station to August 2027.

This recent announcement could not be incorporated into the ISP's scenario analysis, but this sensitivity analysis has been applied to a subset of CDPs for each scenario to verify the ODP. For information regarding the impact on generation and storage development opportunities, see Appendix 2.

Extending the operation of Eraring eliminates the need for dispatchable capacity to be developed in New South Wales in the near term to maintain reliability. The extension of Eraring's operation has little impact on the long term capacity developments, and the NPV of the total system cost of the ODP is lowered by approximately $250 million in *Step Change* and $330 million in *Progressive Change* due to the slower development requirements.

[47] At https://aemo.com.au/consultations/current-and-closed-consultations/draft-2024-isp-consultation.

Table 69 presents the weighted net market benefits of the relevant CDPs in the *Extended Eraring* sensitivity compared with the scenario analysis that applies its earlier closure date. The CBA remains robust to this change with CDP14 remaining the highest-ranked CDP and lower ranked CDPs shifting marginally.

Note that the benefits of an actionable Sydney Ring South, when derived by comparing CDP5 and CDP3, have increased to $77 million. This is driven by an increase in net market benefits associated with actionability in *Progressive Change* (to a net market benefit of $45 million) and in *Green Energy Exports*, where net market benefits increase by $150 million.

The increased benefits of Sydney Ring South in *Green Energy Exports* come from greater benefits associated with avoiding generation and storage capital costs associated in the case with the network augmentation. With Eraring operational for an extra two years, it is expected that greater emissions will be produced, reducing the capability for GPG to provide dispatchable support after it retires. As such, additional storage, solar and wind capacity is instead required across most regions, as flexible gas would need to be reserved for the Sydney, Newcastle and Wollongong subregion without the augmentation. If Sydney Ring South is developed, this GPG can be avoided, reducing therefore the need for alternate storage and renewable generation developments elsewhere to maintain an approximately equivalent emissions outcome within the scenario's carbon budget. Benefits in *Progressive Change* are from avoidance of gas generation.

Table 69 Weighted net market benefits and rankings for key CDPs, (in $ billion) *Extended Eraring* sensitivity and core assumptions

		Extended Eraring sensitivity		Core assumptions	
CDP	**CDP description**	**WNMB**	**WNMB Rank**	**WNMB**	**WNMB Rank**
14	CDP3 with actionable Project Marinus Stage 2	22.03	1	21.83	1
18	CDP3 without actionable Queensland SuperGrid South	22.03	2	21.81	4
3	*Step Change* least- cost DP	22.02	3	21.80	6
24	CDP3 with actionable Project Marinus Stage 2 but without actionable Queensland SuperGrid South	22.02	4	21.82	2
21	CDP3 with actionable Project Marinus Stage 2 but without Sydney Ring South	21.99	5	21.80	5
20	CDP3 without actionable Queensland SuperGrid South nor Sydney Ring South	21.98	6	21.79	7
5	CDP3 without Sydney Ring South	21.95	7	21.82	3

Note: As the sensitivity analysis was implemented to CDPs beyond the top six, higher rankings may be presented. The weighted rankings are relative to only the subset of CDPs modelled, and exclude non-modelled CDPs.

A6.8.2 *Reduced CER Coordination* sensitivity

The *Reduced CER Coordination* sensitivity examines the impact of lower coordination of consumer-owned stationary batteries that can be operated in a coordinated fashion within virtual power plant (VPP) arrangements. This sensitivity explores the impact on the need for utility-scale investments if coordination does not reach the level forecast. VPPs are modelled similar to utility-scale storage technologies, optimising their charge and discharge profiles within the ISP model. The behaviour of passive stationary CER storage on the other hand are not operated to minimise system costs, and are modelled more passively to generally improve individual customer benefits of their assets (which may result in lesser discharge when the system would benefit from it, to retain stored energy overnight and thereby reduce a customer's need to purchase electricity from the grid). For more detail see the ISP Methodology[48].

This sensitivity identifies that the total system costs increase by $4.1 billion with no further coordination of stationary CER batteries than exists currently, as higher levels of medium and deep duration utility storages would be required to compensate for the lack of coordinated embedded storage devices.

This sensitivity has been applied only to *Step Change* as it is not designed to test the robustness of the ODP, but the value of CER coordination.

As seen in Table 70, the impact on weighted net market benefits of the CDPs is relatively minimal. The impacts on the generation and storage developments required without the forecast coordinated CER is relatively similar across CDPs. The CDPs therefore remain relatively robust in terms of rankings, with CDP14 still the highest ranked. The CDPs are also robust in terms of least-worst weighted regrets rankings.

Table 70 Net market benefits and weighted net market benefits for key CDPs, (in $ billion) *Reduced CER Coordination* sensitivity and core assumptions

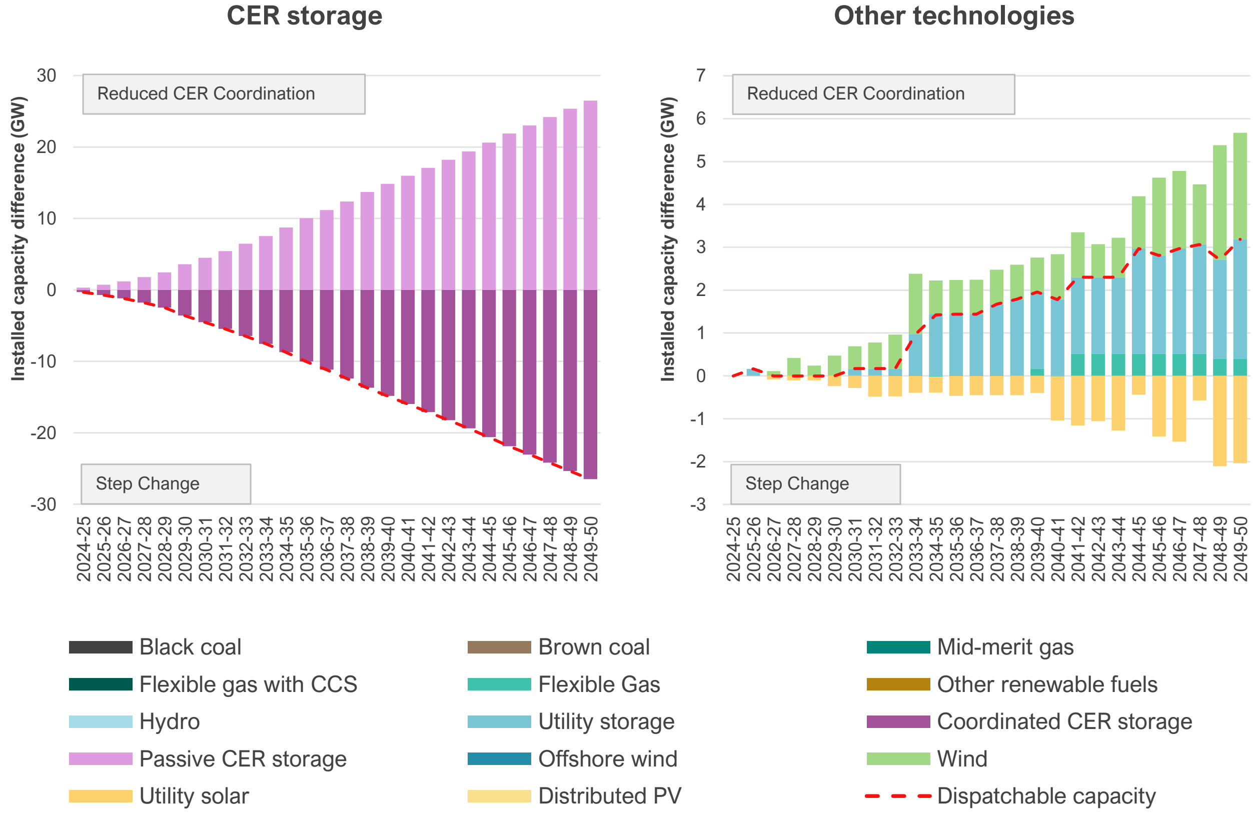
		***Reduced CER Coordination* sensitivity**				**Core assumptions**			
CDP	**CDP description**	***Step Change***	**WNMB**	**WNMB Rank**	**WWR Rank**	***Step Change***	**WNMB**	**WNMB Rank**	**WWR Rank**
14	CDP3 with actionable Project Marinus Stage 2	16.63	21.82	1	8	16.66	21.83	1	9
24	CDP3 with actionable Project Marinus Stage 2 but without actionable Queensland SuperGrid South	16.57	21.80	2	5	16.61	21.82	2	6
21	CDP3 with actionable Project Marinus Stage 2 but without actionable Sydney Ring South	16.64	21.79	3	7	16.67	21.80	5	8
5	CDP3 without actionable Sydney Ring South	16.86	21.77	4	2	16.96	21.80	6	2
16	CDP3 Step without actionable Mid North South Australia REZ Expansion	16.90	21.77	5	4	16.91	21.78	8	5
18	CDP3 without actionable Queensland SuperGrid South	16.80	21.76	6	1	16.91	21.81	4	1
3	*Step Change* least-cost DP	16.85	21.76	7	10	16.94	21.80	6	7

Note: As the sensitivity analysis was implemented to CDPs beyond the top six, higher rankings may be presented. The weighted rankings are relative to only the subset of CDPs modelled, and exclude non-modelled CDPs.

Figure 28 presents the impact on capacity developments in CDP14. The impact on generation and storage developments is further discussed in Appendix 2.

[48] At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/isp-methodology-2023/isp-methodology_june-2023.pdf?la=en.

Figure 28 Capacity differences between *Reduced CER Coordination* sensitivity and *Step Change*, CDP14



A6.8.3 *Additional Load* sensitivity

A number of stakeholders identified in the Draft 2024 ISP consultation that there existed greater load growth potential that they considered was not captured in the scenario collection, despite the high electrification forecast across each scenario. As such, this *Additional Load* sensitivity aims to ascertain the impact of the development of large industrial loads in key NEM regions. In particular, this sensitivity includes:

- Large industrial load in the Eyre Peninsula of South Australia, including up to 13 TWh of additional load by 2029-30, increasing to 16 TWh by 2049-50.
- Additional hydrogen production and green industrial load, and other potential commercial and industrial loads that may develop in response to the new Western Sydney airport, amounting to 2.6 TWh in 2029-30 and growing to 20 TWh by 2049-50, in the Sydney, Newcastle and Wollongong subregion.

This sensitivity has been applied to *Step Change* only. As seen in Table 71, the additional load increases the total system cost and net market benefits across all CDPs, highlighting the benefit of transmission to support growing electricity consumption. CDP14 remains top-ranked and CDP3 sees an improvement in ranking based on weighted net market benefit – higher than CDP18 which slows transmission development relative to CDP3. This suggests that the benefits of earlier development of Queensland SuperGrid South increase in this sensitivity.

The relative market benefits of delivering Hunter Transmission Project and Sydney Ring South at actionable timings similarly improve under the *Additional Load* sensitivity, reflecting the need for timely augmentation into the Sydney, Newcastle and Wollongong subregion to supply potential new loads. For example, comparing CDP14 and

CDP21 (which does not have an actionable Sydney Ring South), the benefits of an actionable timing improve slightly from $29 million under core assumptions to $33 million in this sensitivity.

The value of the Mid North South Australia REZ Expansion increases with the additional industrial load developments in the Eyre Peninsula, increasing from $18 million to $38 million in weighted net market benefits. The identified augmentation supports southerly flow of renewable energy generated in the north of South Australia, and this sensitivity identifies that additional transmission augmentations to support northerly flow into northern South Australia would be preferred if load growth develops as this sensitivity forecasts. This would avoid the need for local dispatchable capacity to ensure that loads can be met during low renewable generation conditions in the area.

Appendix 2 provides more detail on the generation and storage developments forecast under this sensitivity.

Table 71 Net market benefits and weighted net market benefits for key CDPs, (in $ billion) *Additional Load* sensitivity and core assumptions

		Additional Load sensitivity				Core assumptions			
CDP	CDP description	*Step Change*	WNMB	WNMB Rank	WWR Rank	*Step Change*	WNMB	WNMB Rank	WWR Rank
14	CDP3 with actionable Project Marinus Stage 2	43.96	33.57	1	10	16.66	21.83	1	10
21	CDP3 with actionable Project Marinus Stage 2 but without actionable Sydney Ring South	43.97	33.54	2	9	16.67	21.80	5	9
5	CDP3 without actionable Sydney Ring South	44.22	33.54	3	2	16.96	21.82	3	2
3	*Step Change* least-cost DP	44.21	33.52	4	7	16.94	21.80	6	7
24	CDP3 with actionable Project Marinus Stage 2 but without actionable Queensland SuperGrid South	43.82	33.52	5	6	16.61	21.82	2	6
18	CDP3 without actionable Queensland SuperGrid South	44.08	33.49	6	1	16.91	21.81	4	1
12	CDP3 without actionable Hunter-Central Coast REZ Network Infrastructure Project	44.18	33.49	7	8	16.94	21.77	9	8
16	CDP3 without actionable Mid North South Australia REZ Expansion	44.14	33.49	8	5	16.91	21.78	8	5

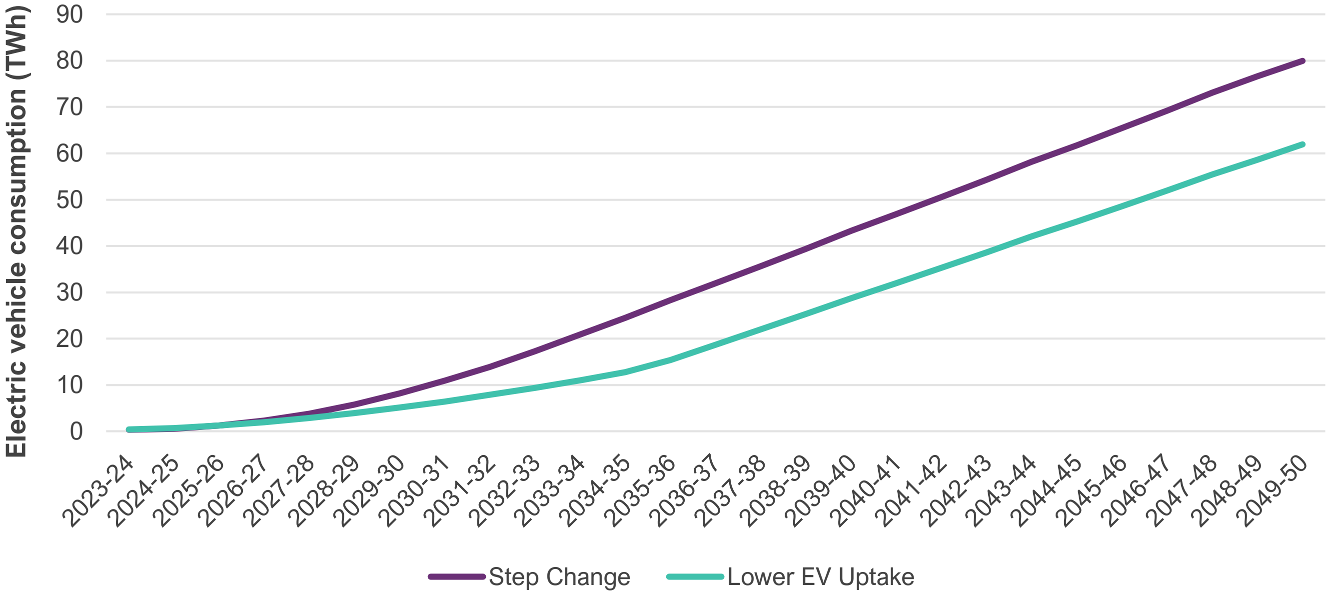
Note: As the sensitivity analysis was implemented to CDPs beyond the top six, higher rankings may be presented. The weighted rankings are relative to only the subset of CDPs modelled, and exclude non-modelled CDPs.

A6.8.4 *Lower EV Uptake* sensitivity

This sensitivity tests alternative assumptions on the uptake of Evs, based on stakeholder feedback on the Draft 2024 Forecasting Assumptions Update consultation (which provided potential assumption changes to forecasts that will apply for the 2024 ESOO).

As seen in Figure 29, after consideration of the feedback to the revised EV uptake forecasts (and resulting electricity consumption), AEMO applied an amended (lowered) EV consumption forecast as a sensitivity to the ISP, in *Step Change* only. This sensitivity identifies that lowering electricity consumption reduces total system costs.

Figure 29 Electric vehicle consumption, *Step Change* and *Lower EV Uptake* sensitivity



As seen in Table 72, this sensitivity results in a reduction in the net market benefit associated with actionable delivery of a number of transmission projects, suggesting that on a weighted net market benefits basis there is lesser value in actioning some projects if load growth is slower from transport electrification.

This demonstrates the uncertainty of the pace of load growth associated with electrification of transport, and is balanced by consideration of industrial load growth in the *Additional Loads* sensitivity.

Table 72 Net market benefits and weighted net market benefits for key CDPs, (in $ billion) *Lower EV Uptake* sensitivity and core assumptions

		Lower EV Uptake sensitivity				Core assumptions			
CDP	CDP description	*Step Change*	WNMB	WNMB Rank	WWR Rank	*Step Change*	WNMB	WNMB Rank	WWR Rank
18	CDP3 without actionable Queensland SuperGrid South	14.87	20.93	1	1	16.91	21.81	4	2
24	CDP3 with actionable Project Marinus Stage 2 but without actionable Queensland SuperGrid South	14.49	20.91	2	6	16.61	21.82	2	7
5	CDP3 without actionable Sydney Ring South	14.85	20.91	3	2	16.96	21.82	3	3
20	CDP3 without actionable Queensland SuperGrid South nor Sydney Ring South	14.88	20.91	4	3	16.92	21.79	7	4
14	CDP3 with actionable Project Marinus Stage 2	14.48	20.90	5	12	16.66	21.83	1	12
3	*Step Change* least-cost DP	14.84	20.89	6	7	16.94	21.80	6	8
16	CDP3 without actionable Mid North South Australia REZ Expansion	14.82	20.88	7	5	16.91	21.78	8	6

Note: As the sensitivity analysis was implemented to CDPs beyond the top six, higher rankings may be presented. The weighted rankings are relative to only the subset of CDPs modelled, and exclude non-modelled CDPs.

A6.8.5 *Constrained Supply Chains* sensitivity

This sensitivity explores how supply chain limitations affecting the rate of investment in generation, storage and transmission infrastructure to transition the NEM impacts the benefits identified in the *Step Change* scenario. A similar sensitivity was performed in the Draft 2024 ISP; this sensitivity now incorporates a number of key changes in assumptions following stakeholder feedback to the Draft 2024 ISP calling for additional risks to be compounded in this sensitivity. These risks now include, following stakeholder feedback:

- Three-year increase to all transmission augmentation lead times (excluding committed and anticipated projects).
- New generation and storage developments (excluding committed and anticipated projects) limited to 4 GW per year to 2029-30, linearly increasing to 14GW per year by 2034-35, to reflect a gradual easement of supply chains as multiple countries target and meet their 2030 and 2035 interim emission reduction targets.
- Transmission, generation and storage build cost increases of 12% to 50% (transmission), and 30% (generation and storage) until 2034-35, reflecting the upper estimate of cost estimation identified in the *Transmission Expansion Options Report*[49] and GenCost report[50] respectively.

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[49] At https://aemo.com.au/-/media/files/major-publications/isp/2023/2023-transmission-expansion-options-report.pdf?la=en.

[50] The 2024 ISP used cost forecasts from the 2022-23 publication of the GenCost report, at https://www.csiro.au/en/research/technology-space/energy/GenCost.

Table 73 Cost increases applied to relevant transmission augmentation in *Constrained Supply Chains* sensitivity

Class	Cost increase	Transmission projects
Class 3	12%	HumeLink
Class 4	30%	VNI West, Project Marinus Stage 1, Project Marinus Stage 2
Class 5	50%	QNI Connect Option 2
Class 5a	30%	Waddamana to Palmerston transfer capability upgrade
Class 5b	50%	Queensland SuperGrid North Option 1, Gladstone Grid Reinforcement, Queensland SuperGrid South Option 1, Queensland SuperGrid South Option 5, New England REZ Transmission Link 1, New England REZ Transmission Link 2, New England REZ Extension, Hunter-Central Coast REZ Network Infrastructure Project, Hunter Transmission Project, Sydney Ring South Option 2d, Mid North South Australia REZ Expansion

The increase in transmission project lead times means that the timings of projects in each CDP in this sensitivity are delayed compared to timings in the corresponding CDPs in *Step Change*. This also results in a three-year shift to the EISDs and timing of actionable windows for each project.

Table 74 shows that there is an overall decrease in net market benefits across all CDPs. While system costs have generally risen under this sensitivity due to the cost increases noted above, the impact of these changes is greater in the CDPs than in the counterfactual. This is a result of the increases applied to transmission build costs which are present in the CDPs but not developed in the counterfactual, and the relatively higher volume of VRE capacity developed in the CDPs through to 2034-35 leading to a greater increase in generator capital costs.

Table 74 Net market benefits and weighted net market benefits for key CDPs, (in $ billion) *Constrained Supply Chains* sensitivity and core assumptions

		***Constrained Supply Chains* sensitivity**				**Core assumptions**			
CDP	**CDP description**	***Step Change***	**WNMB**	**WNMB Rank**	**WWR Rank**	***Step Change***	**WNMB**	**WNMB Rank**	**WWR Rank**
10	CDP3 with actionable New England Transmission Link 2	14.99	20.90	1	7	16.89	21.72	12	14
14	CDP3 with actionable Project Marinus Stage 2	14.27	20.81	2	10	16.66	21.83	1	13
5	CDP3 without actionable Sydney Ring South	14.58	20.80	3	9	16.96	21.82	3	4
21	CDP3 with actionable Project Marinus Stage 2 but without actionable Sydney Ring South	14.29	20.78	4	1	16.67	21.80	5	11
3	*Step Change* least-cost DP	14.57	20.78	5	5	16.94	21.80	6	9
16	CDP3 without actionable Mid North South Australia REZ Expansion	14.53	20.76	6	2	16.91	21.78	8	7
12	CDP3 without actionable Hunter-Central Coast REZ Network Infrastructure Project	14.55	20.75	7	8	16.94	21.77	9	10

Note: As the sensitivity analysis was implemented to CDPs beyond the top six, higher rankings may be presented. The weighted rankings are relative to only the subset of CDPs modelled, and exclude non-modelled CDPs.

The constraint on supply chains would impact on the ability to meet emissions budgets and renewable energy and storage policy targets. Under the sensitivity there is a greater reliance on coal and GPG generation over the period to 2035, as well as to a lesser extent on hydro, given the delayed development of replacement infrastructure. In this sensitivity, the NEM-wide renewable energy share is only 68% by 2029-30, short of the Powering Australia Plan's target of 82%, and emissions to 2049-50 are approximately 109 Mt CO_2-e above the NEM emissions budget for that period. Note that while breaches to the emissions budget results in an increased market benefit class (through emissions reduction benefits, or disbenefit in the event of emissions increases), there is no associated cost or market benefit class that relates to breaching renewable energy and storage targets to 2034-35.

CDP14 remains relatively robust to the changes in assumptions under the *Constrained Supply Chains* sensitivity, being the second best ranked CDP on a weighted net market benefits basis.

A6.8.6 *Low Hydrogen Flexibility* sensitivity

The *Low Hydrogen Flexibility* sensitivity has considered stakeholder feedback to the Draft 2024 ISP which suggested that the degree of electrolyser flexibility assumed in the Draft 2024 ISP was optimistic by balancing hydrogen production over monthly timeframes, and that increased energy storage (either to store energy in electric, chemical, or physical form) would be needed than had been included if that level of flexibility were to be achieved. To accommodate this feedback, AEMO implemented this sensitivity by applying a daily hydrogen production target instead of monthly as was assumed in the Draft 2024 ISP.

Modelling a daily balancing of hydrogen would require about 6.7 GW (solar), 1.3 GW (flexible gas), and 1.8 GW (utility storage) more capacity by 2049-50 compared to *Step Change.* This additional capacity enables daily balancing of hydrogen production and support the low electrolyser flexibility implicitly assumed in the Draft 2024 ISP at a cost of $6.5 billion; the approach does not assess the alternative for hydrogen storage given the focus of the ISP models (as shown in the *ISP Methodology*) is on electricity assets.

The impact on *Step Change*'s net market benefits has reduced by around $500 million compared to the scenario, due the increase in cost in the CDPs (due to the impact on capital expenditure being more significant that the impact on fuel costs, which represents a relatively greater component in the counterfactual).

Recognising that this approach still enabled flexible hydrogen production, AEMO extended the above analysis by forcing a higher load factor on hydrogen production facilities, increasing the load factor to 90% instead of 40-60% as forecast in the Draft 2024 ISP. This reflects that the industrial facilities that may use the hydrogen may require a higher continuous availability of the energy form. Under this variant of the sensitivity, applied to *Step Change*, the total system cost also increased as an even greater amount of VRE and storages are needed to support a less flexible hydrogen demand.

Table 75 Net market benefits and weighted net market benefits for key CDPs, (in $ billion) *Low Hydrogen Flexibility* sensitivity and core assumptions

		Updated Low Hydrogen sensitivity				Core assumptions			
CDP	CDP description	*Step Change*	WNMB	WNMB Rank	WWR Rank	*Step Change*	WNMB	WNMB Rank	WWR Rank
14	CDP3 with actionable Project Marinus Stage 2	16.16	21.62	1	13	16.66	21.83	1	12
5	Step without actionable Sydney Ring South	16.45	21.60	2	4	16.96	21.82	3	3
3	*Step Change* least-cost DP	16.45	21.59	3	9	16.94	21.80	6	8
21	CDP3 with actionable Project Marinus Stage 2 but without actionable Sydney Ring South	16.16	21.58	4	11	16.67	21.80	5	10
16	CDP3 without actionable Mid-North South Australia	16.42	21.57	5	7	16.91	21.78	8	6
24	CDP3 with actionable Project Marinus Stage 2 but without actionable Queensland SuperGrid South	16.02	21.57	6	8	16.61	21.82	2	7
18	CDP3 without actionable Queensland SuperGrid South	16.32	21.55	7	2	16.91	21.81	4	2

Note: As the sensitivity analysis was implemented to CDPs beyond the top six, higher rankings may be presented. The weighted rankings are relative to only the subset of CDPs modelled, and exclude non-modelled CDPs.

A6.8.7 *Alternative Weather Sequence* sensitivity

The *Alternative Weather Sequence* sensitivity simulates alternative weather patterns than were forecast in the scenario analysis to identify the impact of continually poor weather conditions resulting in low VRE output across each year of the forecast horizon. As outlined in the *ISP Methodology*, AEMO models weather variability by combining demand and renewable resource historical data from multiple years, and combining these into 'rolling reference years', to ensure historically observed weather variability is considered across the forecast horizon. This ensures the 'capacity outlook model' that identifies generation and storage capacity developments and estimates the economic value of each CDP includes a broad range of weather patterns affecting the coincidence of customer demand, wind, solar and hydro generation outputs.

For this specific analysis, the rolling reference years are replaced with a single reference year with relatively low renewable resource availability. This approach helps assess the resilience of the generation, storage and transmission developments during periods of unpredicted low renewable energy generation. The constraints applied in the scenarios to limit the development of flexible gas to have regard for weather pattern uncertainty (see Section A6.3) are not applied in this outlier sensitivity.

In this sensitivity, the decline in wind generation availability results in increased alternative investments in utility solar and flexible gas. Forecasts indicate a potential 6.3 GW net increase in solar capacity (a net increase of 4.8 TWh in solar generation) and 0.6 GW more flexible gas by 2041-42, compared to *Step Change*, with a reduction of 2.5 GW of wind capacity (equivalent to a 10.3 TWh reduction in wind output during this period, both due to a reduction in installed capacity and the decline in availability).

As Table 76 highlights, the CDP collection remains robust to this change, with CDP14 remaining top ranked. In *Step Change*, the reduction in net market benefits associated with an actionable timing for Project Marinus Stage 2 has fallen by around $101 million, meaning that the project's ability to increase access to Tasmania's existing hydro and storage assets is of increased value with greater renewable energy production limitations. Other projects, such as Sydney Ring South see their net market benefits fall relative to *Step Change*, although they continue to deliver positive net market benefits.

Relative to the core scenarios, this sensitivity increases costs by around $1 billion, mainly driven by fuel costs and lower emissions reduction benefits throughout the horizon, as more gas generation is required to firm VRE that is consistently experiencing to worse weather conditions.

For more detail on the build differences between the core scenario and this sensitivity, see Appendix 2.

Table 76 Net market benefits and weighted net market benefits for key CDPs, (in $ billion) *Alternative Weather Sequence* sensitivity and core assumptions

		Alternative Weather Sequence sensitivity				Core assumptions			
CDP	CDP description	*Step Change*	WNMB	WNMB Rank	WWR Rank	*Step Change*	WNMB	WNMB Rank	WWR Rank
14	CDP3 with actionable Project Marinus Stage 2	16.75	21.87	1	9	16.66	21.83	1	9
24	CDP3 with actionable Project Marinus Stage 2 but without actionable Queensland SuperGrid South	16.71	21.86	2	6	16.61	21.82	2	6
21	CDP3 with actionable Project Marinus Stage 2 but without actionable Sydney Ring South	16.77	21.85	3	8	16.67	21.80	5	8
5	CDP3 without actionable Sydney Ring South	16.96	21.82	4	2	16.96	21.82	3	2
18	CDP3 without actionable Queensland SuperGrid South	16.89	21.80	5	1	16.91	21.81	4	1
3	*Step Change* least-cost DP	16.93	21.79	6	7	16.94	21.80	6	7

Note: As the sensitivity analysis was implemented to CDPs beyond the top six, higher rankings may be presented. The weighted rankings are relative to only the subset of CDPs modelled, and exclude non-modelled CDPs.

A6.9 NEM-wide distributional effects

The AER's *CBA Guidelines*[51] require AEMO to identify an ODP that promotes the efficient development of the power system. While this assessment is conducted considering only eligible market benefit classes, the CBA guidelines includes the need to provide transparency of the beneficiaries of the identified benefits of the ODP, through distributional effects reporting.

Distributional effects, while not an influence on AEMO's choice of ODP, help understand the beneficiaries of costs and benefits of the ODP:

"Distributional effects consider the distribution of costs and market benefits of an optimal development path – that is, who receives the benefits and who pays the costs. This can be useful for considering the equity of how costs and benefits are distributed across the market. CBA is focussed on efficiency and aggregates costs and benefits across individuals/entities without regard to the equity of the distribution of those costs and benefits. As such, CBA cannot resolve equity issues. However, it can draw attention to them through considering distributional effects, and allow policy makers the opportunity to address these through government policy."[51]

For the 2024 ISP, AEMO has assessed distributional effects for two CDPs under *Step Change* and *Progressive Change*. CDP14 includes various projects delivered within their actionable windows, and CDP25 delays all projects until after their respective actionable windows. By comparing the costs to consumers that arise from these CDPs, AEMO has estimated how distributional effects may arise depending on the development path (including the effect on the ISP development opportunities).

In the NEM, transmission charges and wholesale energy costs in 2021-22[52] made up roughly 8% and 34% respectively of the typical residential electricity bill[53]. The remainder of consumer bills was made up of distribution and metering charges (38%), environmental levies (9%) retailer margins (11%) and GST.

Strengthening the network via inter-regional and intra-regional augmentations will lead to an increase in transmission charges over time, but may also drive reductions in wholesale energy costs and reduce the overall electricity bills paid by consumers.

Reduction in wholesale electricity costs may be driven by:

- Increased competition – increased number of generators able to bid in their units to be dispatched will likely lower the dispatch pool price.
- Reduced generation cost – with renewable generators having low (or no) fuel costs compared to coal and gas-fired generators.
- Increased resilience to outages – reducing the impact of transmission or generator outages, expensive emergency or reserve resources will be required less often.

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51 AER. *Cost benefit analysis guidelines: Guidelines to make the Integrated System Plan actionable*, August 2020, at https://www.aer.gov.au/system/files/AER%20-%20Cost%20benefit%20analysis%20guidelines%20-%2025%20August%202020.pdf.

52 AEMC has not yet published the Residential electricity price trends for 2023. However, the default market offer from AER shows similar break-down of cost components in 2023-24 (see https://www.aer.gov.au/system/files/Default%20market%20offer%20prices%202023-24%20final%20determination.pdf).

53 AEMC. Residential electricity price trends 2021, at https://www.aemc.gov.au/sites/default/files/2021-11/2021_residential_electricity_price_trends_report.pdf.

- Increased resilience to renewable resource availability – with greater access to geographically and technologically diverse renewable resources, fewer forecast periods of reduced energy availability may reduce unserved energy or extreme high prices.

A6.9.1 Consumer cost allocation approach for distributional effects for ISP projects

AEMO has estimated incremental transmission charges to consumers under different CDPs. The regulatory process by which major new transmission investments are passed onto a consumer's bill is complicated by a range of factors. Pricing methodologies tend to vary across TNSPs, jurisdictions and type of consumers. Furthermore, estimating inter-regional transmission use of system (TUoS) charges of cross border assets can be challenging without a sophisticated approach. For these reasons, AEMO's assessment relies on the following simplifying assumptions to strike a balance between practicability and complexity:

- AEMO has estimated distributional effects NEM-wide rather than by jurisdiction.
- While financial markets provide an effective way for retailers to hedge their market exposure, and contract positions (and the gains/losses of these relative to wholesale price exposure) will influence the effective consumer costs, AEMO has applied an approach which uses projected wholesale energy prices as a proxy of wholesale energy charges of consumers' bill, ignoring contract market dynamics.
- AEMO has not distinguished between different types of consumers and load profiles. The overall load profile projection is assumed to be representative for all NEM consumers.
- Changes to distribution charges, retailer margins, metering, environmental policies, and other components of consumer bills have not been considered.
- Transmission costs of existing assets has not been considered, as these assets are equivalent in all development paths. This analysis focuses on the incremental cost associated with new transmission augmentations that vary between CDPs.
- AEMO has applied a half-hourly dispatch modelling approach, rather than reflecting the market's five-minute settlement settings. Generator bidding in this model reflects historical bidding behaviour of existing generators, with new renewable energy projects not involved in strategic bidding behaviour. The forecast therefore represents a plausible future for price and dispatch outcomes, and other plausible futures exist (applying alternative assumptions and/or forecasting techniques).

This assessment focuses on CDP14 and CDP25, which feature different commissioning timings for key transmission augmentations, as outlined in Table 77. The comparison between these two CDPs under both scenarios highlights the potential costs and benefits to consumers of delivering these strategic projects to an actionable timetable.

Table 77 Timing of key transmission augmentations in CDP14 and CDP25 in *Step Change* and *Progressive Change*

Projects	*Step Change*		*Progressive Change*	
	CDP14	CDP25	CDP14	CDP25
HumeLink	2029-30	2032-33	2030-31	2032-33
VNI West	2029-30	2035-36	2034-35	2035-36
Project Marinus Stage 1	2030-31	2036-37	2030-31	2036-37
Project Marinus Stage 2	2037-38	2048-49	2036-37	2038-39
QNI Connect	2034-35	2035-36	2034-35	2039-40

While the CDP comparisons focus on the difference in the timing of these strategic projects, another key component of transmission costs is the REZ augmentations that are developed to connect new renewable energy developments[54]. Like the strategic ISP projects that differ between CDPs, these augmentations are assumed to be regulated assets whose costs are recovered by consumers.

Transmission costs increase over the next decade in all development paths as augmentations are delivered. The transmission costs on a per megawatt hour (MWh) basis is partially offset by the connection and consumption of newly electrified loads (electrification). The timing of when consumers start bearing additional transmission charges associated with network augmentations varies between projects (and development paths), depending on each project's assumed expenditure profile associated with early works, construction, and commissioning costs[55,56].

AEMO's forecast approach to wholesale energy cost is reflective of the transition toward a VRE and storage dominated supply mix with back up from gas generators. The average production cost of energy in the NEM considering only short-run marginal costs is projected to decline because of this. How much consumers will actually end up paying for their energy depends on many factors, such as tariff structures and other influences on market offers and how products such as flexibility/ramping and firming will be traded and remunerated in the future NEM. The extent to which consumers will be willing to participate in the market via demand response will also have a material impact on wholesale energy prices and their own electricity bills, as rewards from market participation could offset some of their other charges.

Considerations of wealth transfer from generators to consumers or between market participants are strongly influenced by market structure, contracting levels, competitive dynamics, and funding arrangements for new REZs or interconnectors. As such, assessments of distributional effects are therefore inherently less certain than the economic cost assessments used in the current CBA framework.

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[54] The annualised cost per annum of REZ augmentations is used as an estimate of transmission charges associated with these investments. These augmentations are optimised by the model linearly and it is therefore challenging to associate each augmentation to a single and discrete project.

[55] Early works involves the regulatory approval of early investment expenditure in order to firm up cost estimates, and enhance planning prior to final investment decision. The project proponents confirm the approved cost recovery through contingent project applications. In general, AEMO assumes that consumers will pay for the recovery of these costs in the forthcoming tariff year from when the forecast expenditure is approved, and that depreciation only occurs once the asset is commissioned. In reality TNSPs might decide how to smooth these costs across regulatory periods.

[56] AEMO has estimated profiles for early works, construction, and commissioning costs for each interconnector based on their EISD and past AER determinations for major transmission projects. Given the uncertainty around the profile and timing of these expenditure for REZ augmentations AEMO has assumed that consumers will start incurring costs from when they become operational.

The ISP focuses on the evolution of the generation technology mix and timing of transmission development and therefore assessment of wealth transfer is excluded from the market benefits assessment as required by the CBA guidelines.

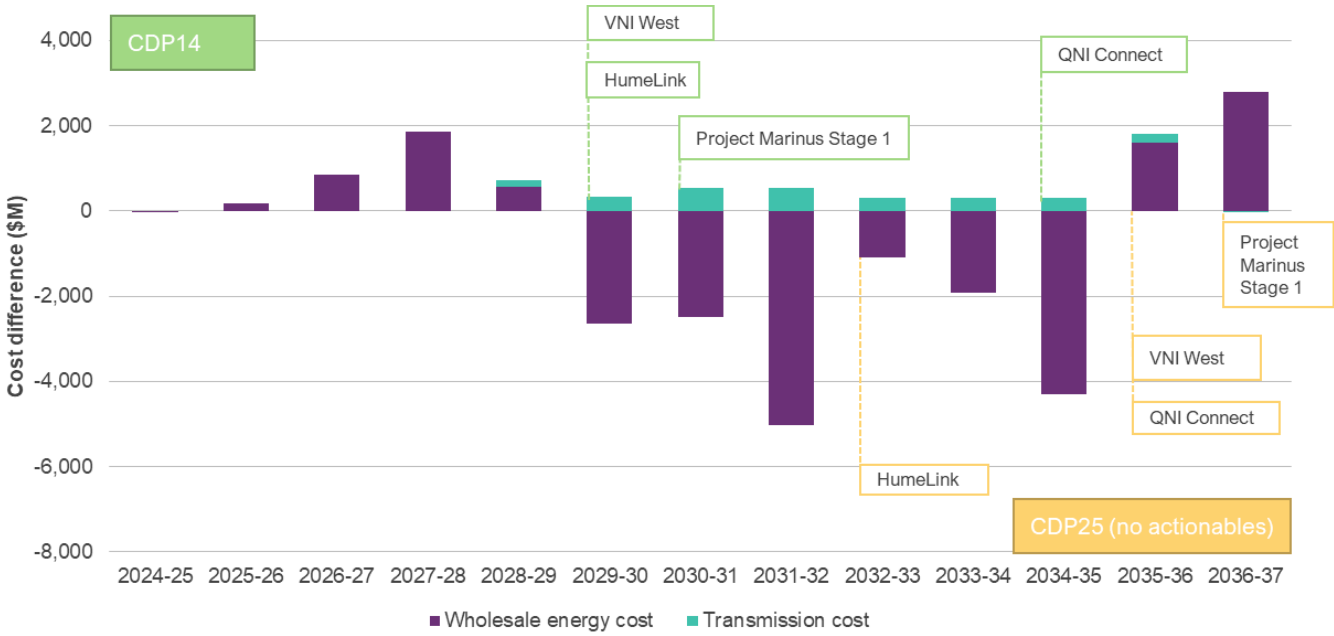
A6.9.2 The benefits and cost to consumers of actionable projects

This section assesses the relative costs and benefit to consumers of either actioning the strategic ISP projects listed in Table 77 above, or delaying these projects into the future. In this way, it provides insights into the potential risk asymmetry between over and under-investment.

Figure 30 shows the average year-on-year differences in wholesale energy (purple bars) and transmission costs (teal bars) between CDP14 and CDP25. This analysis suggests the potential savings in wholesale energy cost far outweigh the additional cost for actioning an earlier commissioning date for the ISP projects. For example, consumers could face a significant increase in wholesale energy costs if the HumeLink and VNI West transmission corridors connecting new renewables and storages (including Snowy 2.0) in Victoria and southern NSW to major load centres in both regions were delayed (under CDP25). This is demonstrated by the significant cost difference between the two CDPs during the period from 2029-30 to 2032-33. Delaying QNI Connect and Project Marinus Stage 1 also shows a similar impact (although less distinctive, given the overlapping project timings that exist between the CDPs).

Differences in interconnector timing between the two CDPs resolve by 2035-36. During the final two years of the analysis, CDP25 forecasts slightly lower wholesale energy cost due to the extra investments (roughly 5 GW in total) in VRE and storages that were required under the delayed transmission pathway.

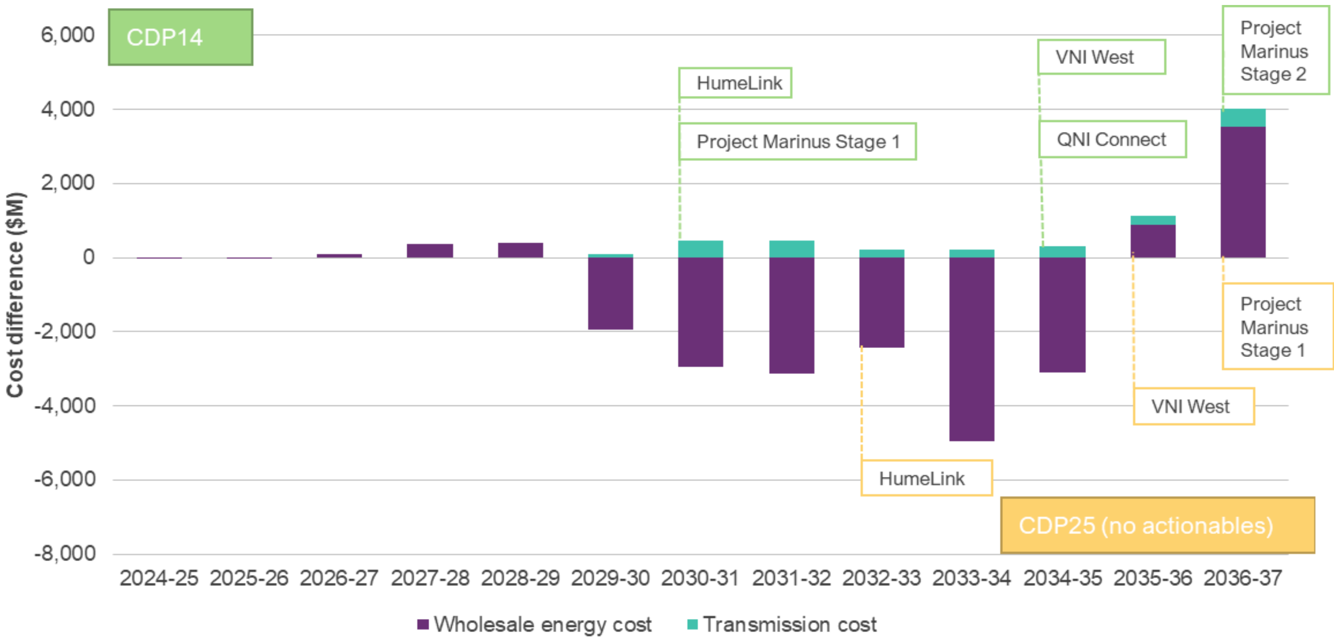
Figure 30 Average year-on-year distributional effects under *Step Change*



The timings of major augmentations in each CDP are denoted by the coloured labels showing the years in which they become operational.

For *Progressive Change*, the slower transmission development path in CDP25 is not as impactful to the distributional effect analysis, due to a less aggressive coal retirement trajectory and slower load growth. Despite this, Figure 31 shows that consumer wholesale energy costs are forecast to be lower with earlier transmission investments during periods from 2030-31 to 2034-35.

Figure 31 Average year-on-year distributional effects under *Progressive Change*



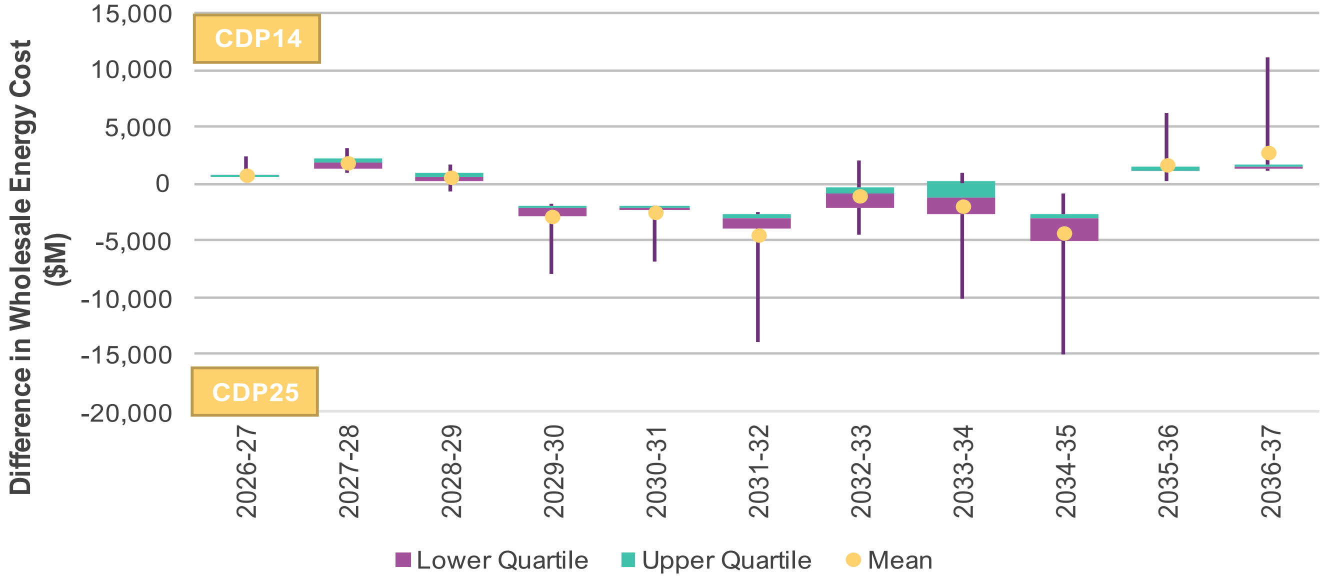
A6.9.3 Considerations on price risk to consumers

Optimal timing in long-term planning models often apply a "just in time" approach, assuming a precise scheduling of new transmission and replacement generation capacity can come online effectively at the same time as coal-fired generation retires. However, bringing in replacement investments slightly ahead of the retirement (particularly for transmission and deep storage investments) may carry a lower risk of elevated consumer costs relative to having replacement investments delivered too late. This potential risk asymmetry would be strongly felt by consumers since new transmission is amortised over many years but price spikes from short-term shortages in supply can lead to very high energy prices. The earlier development of transmission to connect and share new generation capacity that replace coal retirements may be a more prudent sequence of investments for consumers, to mitigate these price risks, should projects become delayed. This potential wealth transfer though between consumers and producers is not an eligible consideration in the ISP's CBA.

Figure 32 shows the distribution of half-hourly differences in wholesale energy costs between CDP14 and CDP25 for *Step Change* presented in the previous section, across different weather conditions and forced outage patterns. Negative differences in costs (CDP14 minus CDP25) indicate that CDP14 is lower cost than CDP25 and vice versa. It demonstrates that greater price volatility exposure is forecast without timely development of further transmission projects to efficiently share new generation developments.

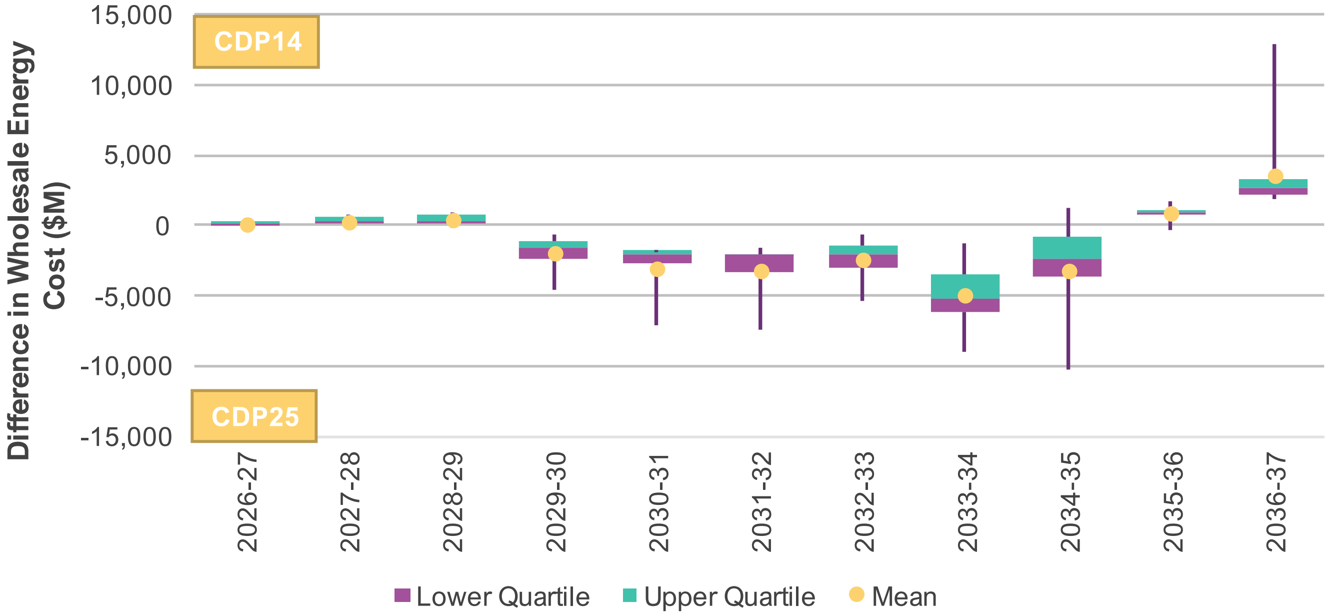
In some years, for example 2031-32 or 2034-35 where HumeLink, VNI West and QNI Connect are developed in CDP14 but not yet available in CDP25, the magnitude of these cost differences is shown to vary considerably depending on weather and outage patterns and is generally skewed towards higher consumer cost outcomes in CDP25 without the earlier availability of these transmission projects. Coal unavailability for instance, if timed with localised low VRE conditions or high demand, can expose consumers to significant price spikes and increased volatility, as greater reliance on gas-fired generation is needed (at higher operating cost). Transmission developments are shown to reduce this risk by providing accessibility of a geographical diverse pool of low-cost VRE resources. In the absence of earlier transmission development in these years, there is an asymmetric risk of more extreme increases in wholesale costs borne to consumers under adverse weather and outage conditions.

Figure 32 Distribution of differences in wholesale energy costs under *Step Change*



A similar trend with less volatile differences in energy cost is projected in *Progressive Change* due to higher coal availability, slower load growth, as seen in Figure 33. However, consumers may be vulnerable to price shocks in 2030-31, 2021-32 (due to HumeLink and Project Marinus Stage 1 delays) and 2033-2034 (due to VNI West and QNI connect delays) under unfavourable weather conditions and generator outages.

Figure 33 Distribution of differences in wholesale energy costs under Progressive Change



A6.10 The impact of consumer risk preferences on transmission timings

Consumer risk preferences

AEMO engaged directly with residential consumers (“consumers”) for the 2024 ISP to better understand their risk preferences related to infrastructure development pathways and decision making. Consumers are exposed to uncertainty, and therefore risk, in relation to the expected cost of their future electricity bills, and the level of volatility in the cost of these bills in the future. The timing of electricity infrastructure investments alters consumers’ exposure to this risk of market volatility.

AEMO’s consumer engagement process was carried out in collaboration with a team of consultants and the results have led to the development of a NEM-first consumer risk preference metric. For a more comprehensive discussion of the process undertaken to develop the metric and how the metric estimates consumers’ risk preferences, please refer to AEMO’s *Summary of consumer risk preferences project*[57].

It is important to note that AEMO did not apply the recently-developed consumer risk preference metric estimate to select an ODP for the 2024 ISP. In future, if AEMO selects an ODP that is not risk neutral (that is, does not maximise the weighted net market benefits of the CDP collection), AEMO may use the metric (or any subsequent updates to the metric) to evaluate how the CDPs perform to reduce volatility in the cost of future electricity bills when selecting the ODP. This analysis would require AEMO to estimate annual residential electricity bills across the modelled period.

The metric allows AEMO to directly compare development path outcomes by estimating the NPV of NEM residential consumers’ aggregate willingness to pay for the difference in volatility (in annual electricity bills) offered by any two CDPs. The aggregate willingness to pay would then be compared with the difference in the cost to residential consumers under both CDPs. This ‘cost to consumers’ would then be taken to be the present value of residential consumer bills across the modelled period and considers the projected residential consumer population.

[57] At https://aemo.com.au/consultations/current-and-closed-consultations/draft-2024-isp-consultation.

A6.11 The optimal development path

As discussed in Section A6.7 and confirmed via section A6.8, **CDP14 is selected as the ODP, on the basis that it provides the highest weighted net market benefits** and is also generally resilient to the sensitivity analysis. In some instances (for example, the *Extended Eraring* sensitivity) it represents improved benefits to other CDPs, reinforcing its appropriateness as the ODP. As seen in Section A6.8 CDP14 remains the top ranked CDP in weighted net market benefits across all but one of the sensitivities after examining each sensitivity in *Step Change*, performing better than all alternative CDPs. Only in the *Lower EV Uptake* sensitivity, which results in a generalised reduction in demand over the modelling horizon, does CDP14 lose its top-ranked status across the CDP collection.

Table 78 Relativity of weighted net market benefits (in $ billion) for each key CDP across the sensitivity collection

CDP	Description	*Core scenarios*	*Extended Eraring*	*Reduced CER Coordination*	*Additional Load*	*Lower EV Uptake*	*Constrained Supply Chain*[A]	*Low Hydrogen Flexibility*	*Alternative Weather Sequence*
Weighted net market benefits									
14	CDP3 with actionable Project Marinus Stage 2	21.83	22.03	21.82	33.57	20.90	20.81	21.62	21.87
24	CDP3 with actionable Project Marinus Stage 2 but without actionable Queensland SuperGrid South	21.82	22.02	21.80	33.52	20.91	20.31	21.57	21.86
5	CDP3 without actionable Sydney Ring South	21.82	21.95	21.77	33.54	20.91	20.80	21.60	21.82
18	CDP3 without actionable Queensland SuperGrid South	21.81	22.03	21.76	33.49	20.93	20.31	21.55	21.80
21	CDP3 with actionable Project Marinus Stage 2 but without actionable Sydney Ring South	21.80	21.99	21.79	33.54	20.86	20.78	21.58	21.85
3	*Step Change* least-cost DP	21.80	22.02	21.76	33.52	20.89	20.78	21.59	21.79
Change in weighted net market benefits relative to the most beneficial CDP									
14	CDP3 with actionable Project Marinus Stage 2	0.00	0.00	0.00	0.00	-0.03	0.00	0.00	0.00
24	CDP3 with actionable Project Marinus Stage 2 but without actionable Queensland SuperGrid South	-0.01	-0.02	-0.02	-0.05	-0.02	-0.49	-0.05	-0.01
5	CDP3 without actionable Sydney Ring South	-0.02	-0.09	-0.05	-0.04	-0.02	-0.01	-0.02	-0.06
18	CDP3 without actionable Queensland SuperGrid South	-0.02	-0.00	-0.06	-0.08	0.00	-0.49	-0.06	-0.07
21	CDP3 with actionable Project Marinus Stage 2 but without actionable Sydney Ring South	-0.03	-0.04	-0.03	-0.03	-0.07	-0.03	-0.03	-0.02
3	*Step Change* least-cost DP	-0.03	-0.01	-0.06	-0.05	-0.04	-0.03	-0.03	-0.08

Note: Cells shaded teal represent the top CDP for each of the sensitivity CBAs.
A. The NEM carbon budget to 2029-30 and the 82% renewable energy target by 2029-30 are both not met under this sensitivity and the costs associated with the breach of these policies are not included in the NPV calculations.

The CBA analysis contained across this Appendix shows that the additional development of Project Marinus Stage 2 within its actionable window, on top of the collection of projects that would deliver the least cost path in *Step Change* if delivered within their actionable windows, appropriately balances the over-investment risk in *Step Change* with the under-investment risks in the other scenarios (given that this project is in the least-cost DP for both *Progressive Change* and *Green Energy Exports* which represent an aggregated weighing of 57%) and the risks explored in the sensitivity analysis summarised above. **Given its robust performance across the set of alternative assumptions tested, AEMO identifies CDP14 as the optimal development path.**

Table 79 presents the set of projects identified as actionable in the 2024 ISP. More detail on each of these projects can be found in Appendix 5.

Table 79 Actionable projects in the optimal development path

Already actionable projects (confirmed in this ISP as continuing to be actionable)	**In service timing advised by proponent**	**Full capacity timing advised by proponent[A]**	**Actionable framework**
HumeLink	Northern: July 2026 Southern: December 2026	Northern: July 2026 Southern: December 2026	ISP
Sydney Ring North (Hunter Transmission Project)	December 2028	December 2028	NSW[B]
New England REZ Network Infrastructure Project (New England REZ Transmission Link)	June 2031[E]	June 2031[E]	NSW[B]
Victoria – New South Wales Interconnector West (VNI West)	December 2028	December 2029	ISP
Project Marinus[C]	Stage 1: June 2030 Stage 2: June 2032	Stage 1: December 2030 Stage 2: December 2032	ISP
Newly actionable projects (as identified in this ISP)	**Earliest feasible in service timing**	**Full capacity timing advised by proponent[A]**	**Actionable framework**
Hunter-Central Coast REZ Network Infrastructure Project (Hunter-Central Coast REZ Expansion)	July 2027	July 2027	NSW[B]
Sydney Ring South	September 2028	September 2028	ISP
Gladstone Grid Reinforcement	March 2029	March 2029	QLD[D]
Mid North South Australia REZ Expansion	July 2029	July 2029	ISP
Waddamana to Palmerston transfer capability upgrade	July 2029	July 2029	ISP
Queensland SuperGrid South	September 2031[F]	September 2031[F]	QLD[D]
Queensland – New South Wales Interconnector (QNI Connect)	April 2032	March 2033	ISP

Note. Details of these projects are found in Appendix 5 Network Investments of this 2024 ISP.
A. The capacity release and timing is conditional on availability of suitable market conditions and good test results.
B. These are actionable New South Wales projects rather than actionable ISP projects. They will progress under the *Electricity Infrastructure Investment Act 2020* (NSW) rather than the ISP framework.
C. Project Marinus is a single actionable ISP project without decision rules.
D. These Queensland projects will progress under the Energy (Renewable Transformation and Jobs) Act 2024 (Qld) rather than the ISP framework.
E. This is the latest project proponent timing provided from EnergyCo for Part 1. The ISP modelling in the appendix applies a date provided to AEMO in December 2023. Please See Appendix 5 for more information.
F. This is the latest project proponent timing provided from Powerlink for Part 1. The ISP modelling in the appendix applies a date provided to AEMO in December 2023. Please See Appendix 5 for more information.

A6.12 Sensitivity analysis from the Draft 2024 ISP

This section reproduces the sensitivity analysis published in the Draft 2024 ISP for convenience. It is important to note that the CDP collection itself has changed since the publication of the Draft 2024 ISP, as discussed in A6.5. Direct comparison between CDPs discussed in this section and the rest of the document cannot therefore be performed. Table 80 below reproduces the CDP collection as published in the Draft 2024 ISP, and should be used as a guide to the CDPs presented **only** in this section. To minimise risk of confusion regarding the make up of CDPs in the 2024 ISP, CDPs have been renumbered in this sub-section using roman numerals instead.

This section outlines the resilience of the Draft 2024 ISP CDPs' identified market benefits to changes in input assumptions used in the core scenarios. CDP XI (CDP III with actionable Project Marinus Stage 2) was ultimately found to be the Draft 2024 ISP's ODP, but it did not include a number of projects that have now been found actionable, as explained in this appendix.

While more CDPs are explored in the sensitivities, the discussion in this sub-section focuses on the five CDPs with the highest weighted net market benefits, unless otherwise stated, to allow for further consideration of additional insights to assist the identification of the ODP as laid out in the Draft 2024 ISP.

Table 80 Candidate development paths in the Draft 2024 ISP

In these CDPs …		… these projects would be actionable													
CDP	**Description**	**Queensland SuperGrid North**	**Gladstone Grid Reinforcement**	**Queensland SuperGrid South**	**QNI Connect**	**New England REZ Transmission Link 1**	**New England REZ Transmission Link 2**	**New England REZ Extension**	**Sydney Ring**	**HumeLink**	**VNI West**	**Project Marinus Stage 1**	**Project Marinus Stage 2**	**TAS Central Highlands REZ Upgrade**	**Mid-North South Australia Upgrade**
Least-cost DPs in each scenario															
I	*Green Energy Exports* least-cost	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
II	*Progressive Change* least-cost		✓	✓					✓	✓	✓	✓	✓	✓	
III	*Step Change* least-cost		✓	✓		✓		✓	✓	✓	✓	✓		✓	
Testing alternatives timings based on CDP III															
IV	CDP III without actionable Sydney Ring		✓	✓		✓		✓		✓	✓	✓		✓	
V	CDP III without actionable HumeLink		✓	✓		✓		✓	✓		✓	✓		✓	
VI	CDP III without actionable VNI West		✓	✓		✓		✓	✓	✓		✓		✓	
VII	CDP III with actionable QNI Connect		✓	✓	✓	✓		✓	✓	✓	✓	✓		✓	
VIII	CDP III without actionable New England REZ Extension		✓	✓		✓			✓	✓	✓	✓		✓	
IX	CDP III with actionable Queensland SuperGrid North	✓	✓	✓		✓		✓	✓	✓	✓	✓		✓	
X	CDP III with actionable Mid-North South Australia Upgrade		✓	✓		✓		✓	✓	✓	✓	✓		✓	✓
XI	CDP III with actionable Project Marinus Stage 2		✓	✓		✓		✓	✓	✓	✓	✓	✓	✓	
XII	CDP III without actionable Project Marinus Stage 1		✓	✓		✓		✓	✓	✓	✓			✓	
XIII	CDP III with actionable Project Marinus Stage 2 and Mid-North South Australia Upgrade		✓	✓		✓		✓	✓	✓	✓	✓	✓	✓	✓
XIV	CDP III with actionable Project Marinus Stage 2 and QNI Connect		✓	✓	✓	✓		✓	✓	✓	✓	✓	✓	✓	
XV	CDP III without actionable Queensland SuperGrid South		✓			✓		✓	✓	✓	✓	✓		✓	
XVI	CDP III without actionable Queensland SuperGrid South and Gladstone Grid Reinforcement					✓		✓	✓	✓	✓	✓		✓	
Testing a CDP with no actionable projects															
XVII	**No actionable projects**														

A6.12.1 *Alternative Discount Rates*

As recommended by the AER's CBA Guidelines, AEMO has explored the impact of alternative discount rates on the key CDPs to assist in understanding the impact of uncertainty around the time-value of money and the weighted average cost of capital (WACC) on the development paths.

As shown in the 2022 ISP sensitivity analysis, the CDP rankings were impacted by alternative discount rate assumptions; and as the core discount rate assumption has increased from the 2022 ISP (as consulted upon in the 2023 IASR), it is appropriate to implement similar sensitivity analyses in this Draft 2024 ISP, across each of the three core scenarios.

As discussed in the 2023 IASR, AEMO uses the same rate as both the discount rate for cost and benefits, and for the WACC for annualising capital costs. The core rate assumption is set at 7% real, pre-tax. As outlined in that publication, AEMO identified that the appropriate upper and lower bound for discount rate assumption that should be used in these sensitivities are:

- Increasing the discount rate to 10.5%, and
- Decreasing the discount rate to 3%.

Applying a higher 10.5% discount rate

Table 81 presents the performance of each of the shortlisted CDPs when applying a 10.5% discount rate.

With a higher discount rate, net market benefits are lower across all CDPs and scenarios due to the reduced present value of future market benefits, and the higher relative costs associated with bringing forward investment.

In this sensitivity, the rankings of the shortlisted CDPs shift markedly. Development paths that have fewer early investments in their respective actionable windows are elevated in the rankings based on weighted net market benefits. Due to delayed investments, higher utilisation of existing assets (such as existing GPG) is observed across all CDPs, including the least-cost DP for *Step Change* (CDP III). In this CDP, approximately 1.7 GW less renewable generation and firming capacity (split between wind, solar, and deep storages) is developed by 2034-35 compared to developments under the central discount rate assumption. As a result, more existing GPG is utilised.

Table 81 Performance of candidate development paths under a 10.5% discount rate sensitivity in all scenarios ($ billion) – ranked in order of descending weighted net market benefits

CDP	*Step Change*	*Progressive Change*	*Green Energy Exports*	Weighted net market benefits	WNMB rank	Worst weighted regrets	Worst weighted regrets rank
XI (ODP)	6.98	2.08	25.68	7.73	1	0.22	1
VIII	7.45	2.31	23.54	7.71	2	0.54	9
III	7.43	2.13	23.82	7.66	3	0.50	7
XIV	6.84	1.80	26.02	7.60	4	0.30	3
VII	7.32	1.85	24.22	7.55	6	0.44	4

Note: As the sensitivity analysis was implemented to CDPs beyond the top five, higher rankings may be presented.

Table 82 highlights the changes in the rankings of CDPs as a result of using a higher discount rate. CDPs that feature fewer transmission augmentations within their actionable windows (such as CDP VIII) see an improvement in their ranking, while CDPs that accelerate investments (such as CDP XIV) are less favourable.

CDP XI remains resilient to the change in assumptions, as it remains the top-ranked in weighted net market benefits and also becomes the top-ranked CDP in worst weighted regrets.

Table 82 Comparison of CDP rankings – 10% discount rate sensitivity and core assumptions

CDP	Description	10.5% discount rate		Core assumptions	
		WNMB rank	WWR rank	WNMB rank	WWR rank
XI (ODP)	CDP III with actionable Project Marinus Stage 2	1	1	1	3
VIII	CDP III without actionable New England REZ Extension	2	9	4	10
III	*Step Change* least-cost DP	3	7	3	8
XIV	CDP III with actionable Project Marinus Stage 2 and QNI Connect	4	3	2	1
VII	CDP III with actionable QNI Connect	6	4	5	4

Note: As the sensitivity analysis was implemented to CDPs beyond the top five, higher rankings may be presented.

The relative difference in weighted net market benefits across the top three-ranked CDPs under core assumptions (CDP XI, CDP XIV and CDP III)demonstrates that accelerated investments in certain projects become increasingly regretful with higher discount rates. While CDP XI remains the top-ranked CDP, the reduction in weighted net market benefits of CDP XIV in comparison to CDP XI would more than triple under a high discount rate, from $37 million to $128 million.

Applying a lower 3% discount rate

The effect of a lower discount rate is the inverse of that observed when using higher discount rate assumptions described in the previous section. The net market benefits of all CDPs across scenarios are higher than the core scenarios, as future benefits are valued more highly. For the top-ranked CDPs, the net market benefits using a 3% discount rate are given in the table below.

Table 83 Performance of candidate development paths under a 3% discount rate sensitivity in all scenarios ($ billion) – ranked in order of weighted net market benefits

CDP	*Step Change*	*Progressive Change*	*Green Energy Exports*	WNMB	WNMB rank	Worst weighted regrets	Worst weighted regrets rank
XIV	42.74	18.71	95.27	40.53	1	0.25	1
XI (ODP)	42.77	18.71	94.50	40.42	2	0.36	3
VII	43.12	18.64	93.33	40.37	4	0.54	4
III	43.13	18.64	92.54	40.25	5	0.66	8
VIII	42.95	18.78	92.27	40.20	7	0.70	9

Note: As the sensitivity analysis was implemented to CDPs beyond the top five, higher rankings maybe presented.

In this sensitivity, earlier transmission investments (if effective at lowering costs as a result) provide greater value than under core discount rate assumption. Table 83 shows the performance of key CDPs under the low discount rate sensitivity and demonstrates the changes in the CDP rankings. CDP XIII is not included in the shortlisted CDPs but is included in this table as it becomes the third-ranked CDP under this sensitivity.

Table 84 Comparison of CDP rankings – 3% discount rate sensitivity and core assumptions

CDP	Description	3% discount rate		Core assumptions	
		WNMB rank	WWR rank	WNMB rank	WWR rank
XIV	CDP III with actionable Project Marinus Stage 2 and QNI Connect	1	1	2	1
XI (ODP)	CDP III with actionable Project Marinus Stage 2	2	3	1	3
XIII	CDP III with actionable Project Marinus Stage 2 and Mid-North South Australia Upgrade	3	2	7	2
VII	CDP III with actionable QNI Connect	4	4	5	4
III	*Step Change* least-cost DP	5	8	3	8
VIII	CDP III without actionable New England REZ Extension	7	9	4	10

Note: As the sensitivity analysis was implemented to CDPs beyond the top five, higher rankings may be presented.

With the lower discount rate, earlier investments in QNI Connect, Project Marinus Stage 2 and the Mid North South Australia augmentation (as evaluated in CDP VII, CDP XI, CDP XIV and CDP XIII) improve, and are now the top-ranked CDPs in terms of both weighted net market benefits and worst weighted regrets.

CDP XI is reasonably resilient to the reduction in discount rate, falling only behind CDP XIV in weighted net market benefits and remaining third best in worst weighted regrets. This demonstrates that if faster transition is driven by a lower discount rate, there are broader benefits from the transmission built in this CDP.

Table 85 presents the change in net market benefits associated with CDP XI, CDP XIV and CDP III under the core assumptions and with a 3% discount rate. The reduction in net market benefits associated with CDP III relative to CDP XI (which includes Project Marinus Stage 2 as actionable) more than doubles with a low discount rate, from $72 million to $168 million. The improved benefits of delivering Project Marinus Stage 2 earlier under this sensitivity are underscored by CDP XI now being preferred to CDP III in *Progressive Change*. Finally, CDP XIV becomes the top-ranked CDP for weighted net market benefits, driven largely by increases in benefits in *Progressive Change* where it is now the highest ranked among shortlisted CDPs.

Table 85 CDP XI, CDP XIV and CDP III, core assumptions and 3% discount rate ($ billion)

Discount rate	CDP	*Step Change*	*Progressive Change*	*Green Energy Exports*	WNMB	Reduction in WNMB relative to CDP11	WNMB ranking
Core assumptions	XI (ODP)	17.35	7.24	46.35	17.45	-	1
	XIV	17.25	7.06	46.93	17.42	-0.04	2
	III	17.85	7.25	44.41	17.38	-0.07	3
With 3% discount rate	XI (ODP)	42.77	18.71	94.50	40.42	-	2
	XIV	42.74	18.71	95.27	40.53	0.11	1
	III	43.13	18.64	92.54	40.25	-0.17	5

Note: As the sensitivity analysis was implemented to CDPs beyond the top five, higher rankings may be presented.

A6.12.2 *Rapid Decarbonisation*

The *Rapid Decarbonisation* sensitivity examines the impact of increasing the pace of decarbonisation efforts in the NEM by applying the NEM carbon budget from *Green Energy Exports* to *Step Change.* The lower carbon budget is effectively aligned with sufficient emissions reduction in the NEM to provide a commensurate contribution to global efforts to limit temperature rise to 1.5°C by 2100. For more detail on the underlying carbon budgets, see Section 3.2.3 of the 2023 IASR.

In this analysis, the sensitivity was applied as a direct replacement for *Step Change*, effectively reflecting an early commitment to even greater emissions reduction in a future which otherwise matches AEMO's most likely scenario. Table 86 presents the outcome of substituting the cost-benefit analysis from *Step Change* with the *Rapid Decarbonisation* sensitivity, focusing on the list of shortlisted CDPs laid out in Section A6.7 as well as CDP1 (the least-cost DP for *Green Energy Exports*).

Similar to the insights within *Green Energy Exports*, a faster pace of decarbonisation in the NEM is forecast to lead to higher net market benefits for investments that improve the transition to net-zero by developing renewable energy and firming developments to replace a faster rate of retirement of the incumbent coal fleet.

As Table 86 shows, the impact of a tighter carbon budget across the NEM increases the benefits of CDP1. This demonstrates that the pace of decarbonisation in the NEM, rather than the growth in green energy export potential, is a bigger driver of near-term investments.

CDP XIV (which has both Project Marinus Stage 2 and QNI Connect delivered in their respective actionable windows) is the second highest-ranked CDP shortlisted – demonstrating the higher benefits from transmission development under higher decarbonisation action – and is followed by CDP XI. Both these CDPs highlight that early development of the Project Marinus Stage 2 would increase the resilience of consumer benefits to the uncertainty that exists regarding the pace of emissions reduction facing the NEM.

Table 86 Net market benefits and weighted net market benefits of key CDPs (in $ billion), *Rapid Decarbonisation* and core assumptions

		With *Rapid Decarbonisation* sensitivity			With core *Step Change*		
CDP	**CDP description**	***Rapid Decarbonisation* (NMB)**	**WNMB**	**WNMB Rank**	***Step Change* (NMB)**	**WNMB**	**WNMB Rank**
I	*Green Energy Exports* least-cost DP	26.44	21.04	1	17.11	17.02	10
XIV	CDP III with actionable Project Marinus Stage 2 and actionable QNI Connect	25.61	21.02	2	17.25	17.42	2
XI (ODP)	CDP III with actionable Project Marinus Stage 2	25.48	20.95	3	17.35	17.45	1
VII	CDP III with actionable QNI Connect	25.66	20.75	5	17.79	17.36	5
III	*Step Change* least-cost DP	25.55	20.69	7	17.85	17.38	3
VIII	CDP III without actionable New England REZ Extension	25.41	20.67	8	17.78	17.38	4

Note: As the sensitivity analysis was implemented to CDPs beyond the top five, higher rankings may be presented.

The regrets associated with CDP I decrease in this sensitivity, given the shift towards greater transmission augmentation being preferred. It improves to become the fourth-best CDP regarding worst weighted regrets, up from tenth-best under core assumptions. CDP XI remains third-best, but CDP XIV and CDP XIII are ranked first and second.

A6.12.3 *Reduced Energy Efficiency*

The *Reduced Energy Efficiency* sensitivity examines the impact to generation, storage and transmission investment needs if consumers stagnate in their investments once existing policies expire across the NEM. Energy efficiency investments lead to a more productive energy sector, with lower electricity consumption. This sensitivity replaces the energy efficiency savings in *Step Change* with an energy efficiency savings trajectory that results in similar outcomes than *Progressive Change* in 2039-40, continuing then to grow at a slower pace as the lack of policy expansion hinders energy efficiency savings. More information on this trajectory is available in the 2023 IASR.

The effect of lowering energy efficiency investments, as shown in Figure 34, is that more energy must be generated and supplied by the grid to support industrial, business, and residential consumers. This requires greater investments in renewable energy and storage developments, and increases the benefits associated with transmission investments.

Figure 34 Difference in NEM annual consumption between *Step Change* and *Reduced Energy Efficiency*

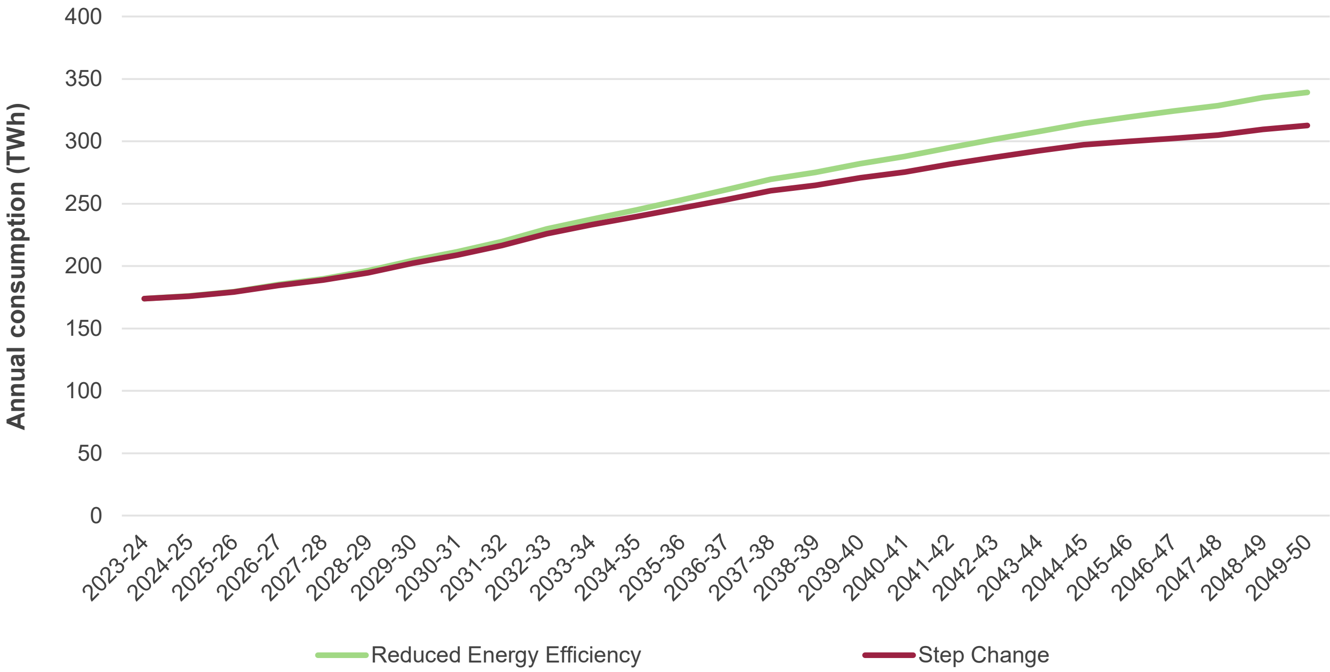


Table 87 highlights how the ranking of CDPs remains relatively resilient to this change, when based on weighted net market benefits. Furthermore, the quantum of net market benefits under this sensitivity does not change significantly, as the change in assumptions impacts only the second half of the outlook period for both the counterfactual DP and all CDPs.

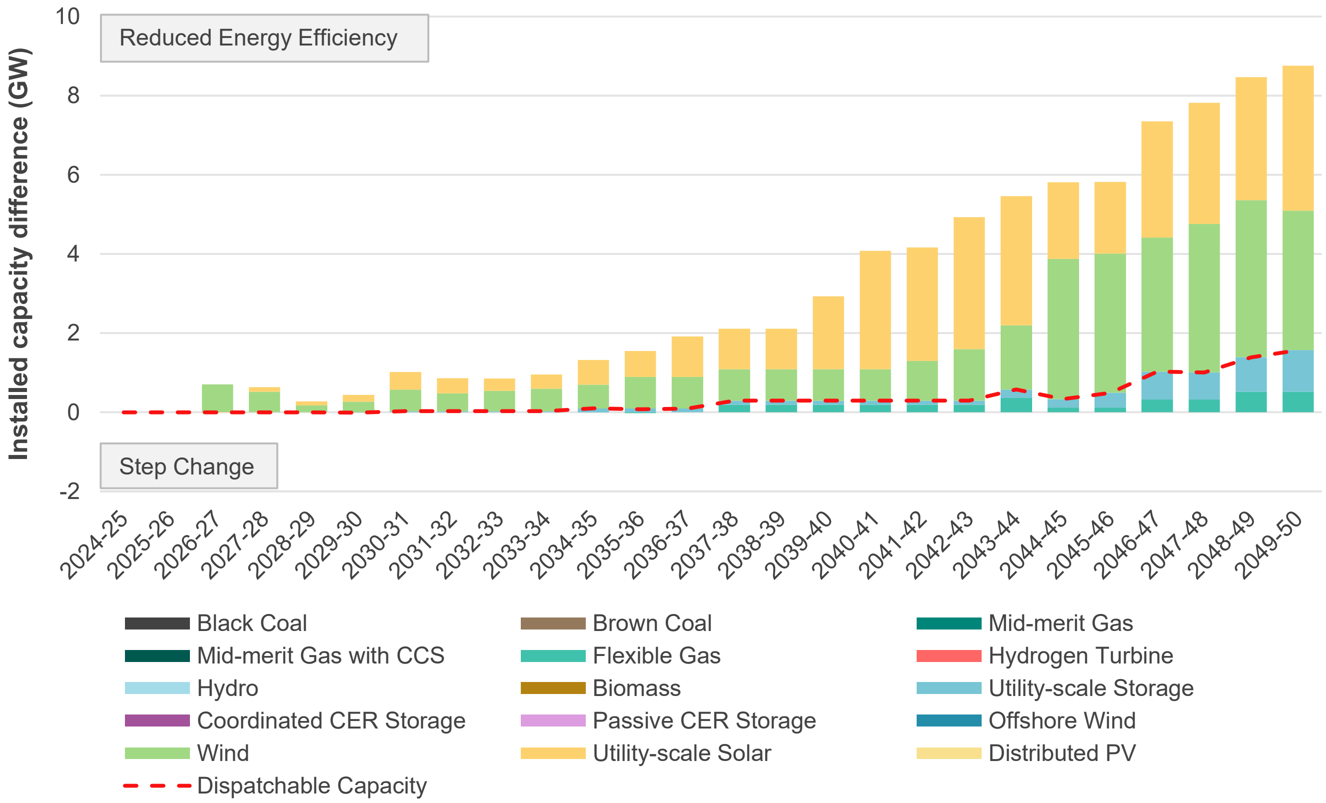
Table 87 Net market benefits and weighted net market benefits for key CDPs, (in $ billion) *Reduced Energy Efficiency* sensitivity and core assumptions

		Reduced energy efficiency sensitivity			With core *Step Change*		
CDP	**CDP description**	***Step Change* with reduced energy efficiency (NMB)**	**WNMB**	**WNMB Rank**	***Step Change* (NMB)**	**WNMB**	**WNMB Rank**
XI (ODP)	CDP III with actionable Project Marinus Stage 2	17.46	17.50	1	17.35	17.45	1
XIV	CDP III with actionable Project Marinus Stage 2 and QNI Connect	17.38	17.48	2	17.25	17.42	2
III	*Step Change* least-cost DP	17.90	17.40	3	17.85	17.38	3
VIII	CDP III without actionable New England REZ Extension	17.80	17.39	4	17.78	17.38	4
VII	CDP III with actionable QNI Connect	17.84	17.38	5	17.79	17.36	5

Note: As the sensitivity analysis was implemented to CDPs beyond the top five, higher rankings may be presented.

As Figure 35 shows, the impact of reduced energy efficiency leads to a much greater need for renewable energy developments to service the higher operational demand, with commensurate increases in firming capacity provided by GPG and storage in the latter part of the horizon.

Figure 35 Difference in capacity between the least-cost DP for *Step Change* and for *Reduced Energy Efficiency* sensitivity



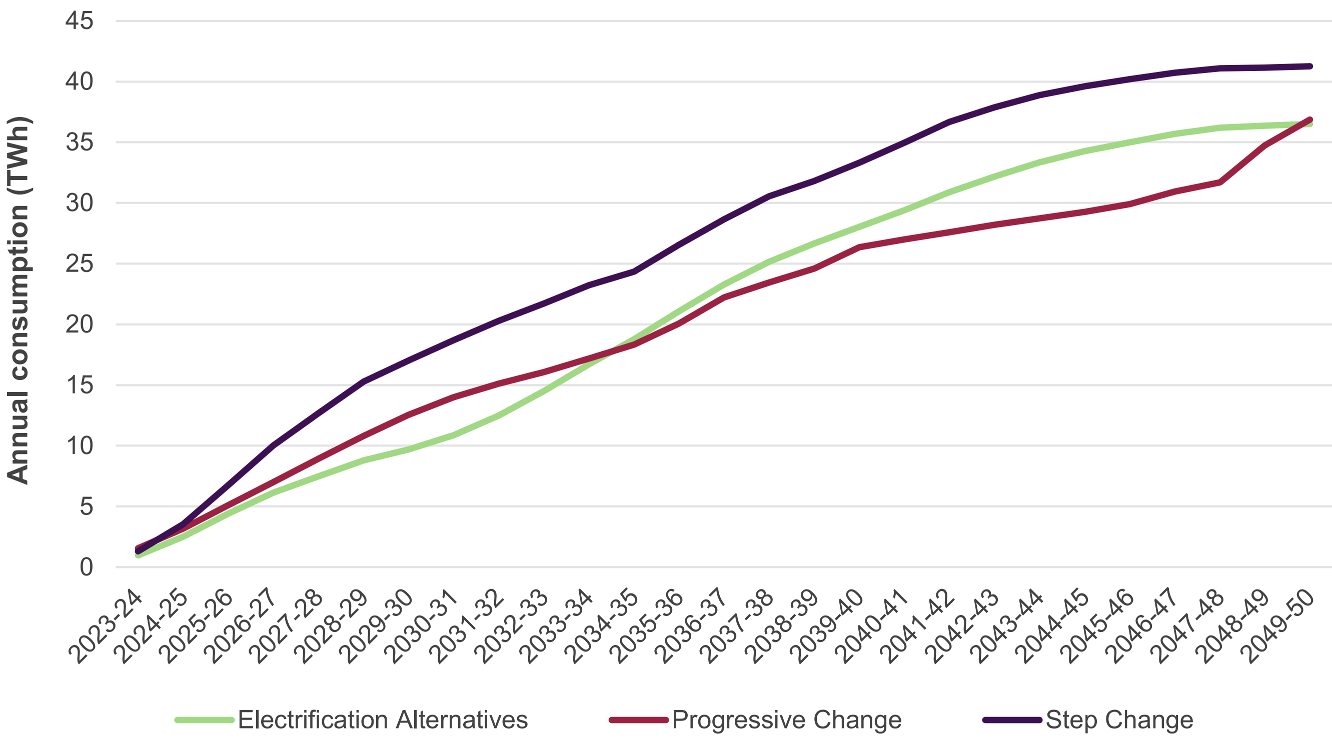
This means that if energy efficiency measures do not materialise as much as is forecast in the *Step Change* scenario, but to the level assumed in this sensitivity instead, then system costs would increase by a present value of between $4.95 billion and $5.39 billion. This demonstrates the significant value to consumers of these investments, so long as the cost of the investments (which are not included in this calculation) is less than approximately $5 billion.

The worst weighted regrets rankings are relatively resilient to this sensitivity to *Step Change* given the limited impacts described above.

A6.12.4 *Electrification Alternatives*

The *Electrification Alternatives* sensitivity, applied to *Step Change*, explores the impact of delayed and deferred industrial electrification, including from increased penetration of biomethane as a molecular alternative to electricity for decarbonising high-heat industrial processes, as stated in the 2023 IASR. This is implemented by using a lower electrification forecast compared to *Step Change*. Figure 36 shows the difference between the electrification forecast for *Step Change, Progressive Change,* and the *Electrification Alternatives* sensitivity.

Figure 36 Electrification forecasts across *Step Change*, *Progressive Change*, and *Electrification Alternatives*



With lower energy consumption needs in this sensitivity compared with *Step Change*, the benefits of transmission investments that support renewable energy expansion all reduce. The net market benefits for each of the CDPs have all decreased under this sensitivity compared to those from *Step Change* as seen in Table 88. However, while the reductions are generally similar across the CDP collection, the biggest reduction amongst the top-ranked CDPs is for CDP VII which features QNI Connect as the increase in demand due to lower electrification is mostly felt in Queensland. Taking into account the weighted net market benefits, CDP XI still has the highest weighted net market benefits.

Table 88 Net market benefits and weighted net market benefits for key CDPs (in $ billion), *Electrification Alternatives* sensitivity and core assumptions

		With *Electrification Alternatives* sensitivity			With core *Step Change*		
CDP	**CDP description**	***Step Change* with *Electrification Alternatives* (NMB)**	**WNMB**	**WNMB Rank**	***Step Change* (NMB)**	**WNMB**	**WNMB Rank**
XI (ODP)	CDP III with actionable Project Marinus Stage 2	16.83	17.23	1	17.35	17.45	1
VIII	CDP III without actionable New England REZ Extension	17.33	17.19	2	17.78	17.38	4
XIV	CDP III with actionable Project Marinus Stage 2 and actionable QNI Connect	16.72	17.19	3	17.25	17.42	2
III	*Step Change* least-cost DP	17.33	17.16	4	17.85	17.38	3
VII	CDP III with actionable QNI Connect	17.23	17.12	5	17.79	17.36	5

Note: As the sensitivity analysis was implemented to CDPs beyond the top five, higher rankings may be presented.

The worst weighted regrets rankings are relatively resilient to this sensitivity to *Step Change* given the limited impacts described above.

A6.12.5 *Constrained Supply Chains*

The *Constrained Supply Chains* sensitivity explores how limitations in the rate of investment in infrastructure to transition the NEM impacts the costs and benefits of developments in generation, storage, and transmission in *Step Change*. This is to reflect potential constraints in supply chain capacity and workforce availability as the NEM rapidly transitions towards a more interconnected and renewables-dominated system.

These limitations have been reflected through the following adjustments in inputs:

- Two-year increase to all transmission augmentation lead times (excluding committed and anticipated projects).
- New generation and storage developments limited to 4 GW of additional capacity NEM-wide per year until 2029-30.

The increase in transmission project lead times means that the timings of projects in each CDP in this sensitivity are delayed compared to timings in the corresponding CDPs in *Step Change*. This also results in a two-year shift to the EISDs and timing of actionable windows for each project.

Table 89 presents the net market benefits and rankings of the shortlisted CDPs in the *Constrained Supply Chains* sensitivity compared to *Step Change* with core assumptions. With the restrictions in how much generation capacity can be developed annually and longer lead times for transmission, there is greater urgency to commence work on transmission projects so they can still meet system needs in a timely manner. As such, CDPs which have more actionable projects are more favourable in this sensitivity.

For example, the relative difference in weighted net market benefits between CDP XI (which has an actionable Project Marinus Stage 2) and CDP III increases from $72 million in core scenarios with *Step Change* to $110 million in Constrained Supply Chains sensitivity. CDP VII (with an actionable QNI Connect) becomes the top-ranked CDP in *Step Change* under this sensitivity, followed by CDP III. This demonstrates that if supply chains are at risk of being constrained, then progressing sooner with the necessary transmission developments, to reduce the period for which the infrastructure will effectively be delayed by supply chain constraints, is of increasing benefit to minimise costs.

The constraint on supply chains would impact on the ability to meet the NEM emissions budget to 2029-30 and the 82% renewable energy target by 2029-30. In this sensitivity, total renewable energy share is only 62% by 2030, and in emissions until 2030 are over by approximately 155Mt CO_2-e. The cost associated with the breach of these policies are not included in the NPV calculations for this sensitivity.

CDP XI remains resilient to the impact of limitations on supply chains and retains its position as the top-ranked CDP on the basis of weighted net market benefits.

Table 89 Net market benefits and weighted net market benefits for key CDPs (in $ billion), *Constrained Supply Chains* sensitivity and core assumptions

		With *Constrained Supply Chains* sensitivity			With core *Step Change*		
CDP	**CDP description**	***Step Change with Constrained Supply Chains* (NMB)[A]**	**WNMB**	**WNMB rank**	***Step Change* (NMB)**	**WNMB**	**WNMB rank**
XI (ODP)	CDP III with actionable Project Marinus Stage 2	22.04	19.47	1	17.35	17.45	1
XIV	CDP III with actionable Project Marinus Stage 2 and QNI Connect	22.02	19.47	2	17.25	17.42	2
VII	CDP III with actionable QNI Connect	22.47	19.38	3	17.79	17.36	5
VIII	CDP III without actionable New England REZ Extension	22.39	19.37	4	17.78	17.38	4
III	*Step Change* least-cost DP	22.45	19.36	5	17.85	17.38	3

Note: As the sensitivity analysis was implemented to CDPs beyond the top five, higher rankings may be presented.
A. The NEM carbon budget to 2029-30 and the 82% renewable energy target by 2029-30 are both not met under this sensitivity and the costs associated with the breach of these policies are not included in the NPV calculations.

This sensitivity on *Step Change* sees no major change in worst weighted regrets across the CDP collection, and no changes to the rankings of the CDPs on this basis. Worst weighted regrets remain driven by under-investment in *Green Energy Exports*.

A6.12.6 *Reduced Social Licence*

For the first time this year, AEMO has conducted social licence-specific sensitivity analysis to explore some of the impacts and risks associated with low social licence for infrastructure options considered in the 2024 ISP. AEMO consulted on sensitivity principles and parameters with members of the Advisory Council on Social Licence and the ISP Consumer Panel.

This sensitivity explored the impact to the benefits provided by key CDPs if social licence risks are not adequately addressed. The *Reduced Social Licence* sensitivity broadly applies increases to transmission and pumped hydro capital costs by 15%, to REZ generation costs for onshore wind and solar between 5% and 60% based on private land parcel density, and to transmission project lead times by two years to reflect increased social licence risks. Refer to Appendix A.8 for the inputs and assumptions for the *Reduced Social Licence* sensitivity.

Results for net market benefits, weighted net markets benefits, and rankings of the key CDPs are provided in Table 90. The table shows that the reduction in net market benefits as compared with *Step Change*, which is approximately $4 billion across the CDPs, is highest for those CDPs (CDP XI and CDP XIV) with higher net market benefits to start with. This demonstrates the potential impact of low social licence on the CDPs with the selected parameters for the social licence sensitivity.

Additionally, if the challenges around lack of community acceptance are not sufficiently addressed that it impacts the relevant parameter assumed in this sensitivity, it would require the system an additional cost ranging from $7.91 billion to $8.78 billion in net present value terms.

On weighted net market benefits basis, CDP VIII jumps to the top of the rankings as it naturally has lower VRE development, but CDP11 comes in a close second.

Table 90 Net market benefits and weighted net market benefits for key CDPs, (in $ billion) *Reduced social licence* sensitivity and core assumptions

		With *Reduced social licence* sensitivity			With core *Step Change*		
CDP	**CDP description**	***Step Change with reduced social licence* (NMB)**	**WNMB**	**WNMB rank**	***Step Change* (NMB)**	**WNMB**	**WNMB rank**
VIII	CDP III without actionable New England REZ Extension	13.98	15.75	1	17.78	17.38	4
XI (ODP)	CDP III with actionable Project Marinus Stage 2	13.37	15.74	2	17.35	17.45	1
III	*Step Change* least-cost DP	14.01	15.73	3	17.85	17.38	3
XIV	CDP III with actionable Project Marinus Stage 2 and QNI Connect	13.32	15.73	4	17.25	17.42	2
VII	CDP III with actionable QNI Connect	13.96	15.72	5	17.79	17.36	5

Note: As the sensitivity analysis was implemented to CDPs beyond the top five, higher rankings may be presented.

In this sensitivity on *Step Change,* the worst weighted regrets associated with CDP XIII increase as, unlike in most other CDPs, it is not driven by *Green Energy Exports.* It shifts it to be third-ranked (instead of second) and results in CDP XI becoming second ranked. Other rankings remain robust to the sensitivity.

A6.12.7 Development of Pioneer-Burdekin Pumped Hydro Project

In the 2024 ISP, the Pioneer-Burdekin Pumped Hydro Project – a key strategic deep storage project located in North Queensland identified in the Queensland Energy and Jobs Plan – is insufficiently advanced to be treated as either committed or anticipated. As such, it was treated as a potential new development candidate (distinct from the Borumba Dam Pumped Hydro, which is classified as an anticipated project).

This sensitivity explored the impact to the benefits provided by key CDPs in both *Step Change* and *Progressive Change* if Pioneer-Burdekin Pumped Hydro Project were an anticipated project and developed as indicated in the Queensland Energy and Jobs Plan. In this sensitivity, the project is delivered in two stages as per the Queensland Energy and Jobs Plan[58]– 2.5 GW/60 GWh to commence operation in 2032-33, and a second 2.5 GW/60 GWh stage in 2035-36. Results for net market benefits, weighted net markets benefits, and rankings of the key CDPs are provided in Table 91.

Table 91 Net market benefits and weighted net market benefits for key CDPs (in $ billion), Pioneer-Burdekin Pumped Hydro Project sensitivity and core assumptions

		With sensitivity assumptions				With core assumptions			
CDP	**CDP description**	***Step Change* (NMB)**	***Progressive Change* (NMB)**	**WNMB**	**WNMB rank**	***Step Change* (NMB)**	***Progressive Change* (NMB)**	**WNMB**	**WNMB rank**
XI (ODP)	CDP III with actionable Project Marinus Stage 2	17.15	6.82	17.19	1	17.35	7.24	17.45	1
III	*Step Change* least-cost DP	17.68	6.83	17.13	2	17.85	7.25	17.38	3
VIII	CDP III without actionable New England REZ Extension	17.55	7.01	17.11	3	17.78	7.44	17.38	4
XIV	CDP III with actionable Project Marinus Stage 2 and QNI Connect	17.05	6.46	17.08	4	17.25	7.06	17.42	2
IX	CDP III with actionable Queensland SuperGrid North	17.63	6.49	17.04	5	17.50	6.70	17.07	8
VII	CDP III with actionable QNI Connect	17.58	6.47	17.03	6	17.79	7.07	17.36	5

Note: As the sensitivity analysis was implemented to CDPs beyond the top five, higher rankings may be presented.

CDP XI remains the top-ranked CDP in terms of weighted net market benefits. Improving the connection to this new storage facility in North Queensland via transmission augmentation is more beneficial in this sensitivity, as demonstrated by the improved ranking of CDP IX – which develops the Queensland SuperGrid North project within its actionable window – to fifth best.

[58] Queensland Government, *Queensland SuperGrid Infrastructure Blueprint*, September 2022, page 37, at https://www.epw.qld.gov.au/__data/assets/pdf_file/0030/32988/queensland-supergrid-infrastructure-blueprint.pdf.

Conversely, the benefits of an early development of QNI Connect are reduced, as the development of Pioneer-Burdekin Pumped Hydro Project reduces the need for imports from New South Wales. CDP XIV and CDP VII, which both develop QNI Connect in its actionable window, are relegated to worse rankings.

To understand the impact of this sensitivity, Table 92 compares relevant CDPs against CDP III, which is used as a reference as it provides similar set of projects to all relevant CDPs. Delivering Queensland SuperGrid North within its actionable window (2030-31 to 203132) is still less optimal than delivering the project at the same time as the connection of Pioneer-Burdekin Pumped Hydro Project itself (which is after its actionable window closes). However, with Pioneer-Burdekin Pumped Hydro Project assumed to develop, the relative regrets of earlier investment are reduced, as the transmission will be an important complement to the storage development once delivered. This is shown in the improvement of CDP IX under this sensitivity relative to other CDPs. While CDP IX delivers $311 million less weighted market benefits than CDP III under core assumptions, this difference falls to just $93 million if Pioneer-Burdekin Pumped Hydro Project is developed.

Table 92 Change in net market benefits relative to CDP III (in $ billion), Pioneer-Burdekin Pumped Hydro Project sensitivity and core assumptions

CDP	CDP description	Sensitivity	Benefits relative to CDP III		
			Step Change	*Progressive Change*	WNMB
VII	CDP III with actionable QNI Connect	Core assumptions	-0.06	-0.18	-0.02
		Pioneer-Burdekin Pumped Hydro Project sensitivity	-0.10	-0.35	-0.11
IX	CDP III with actionable Queensland SuperGrid North	Core assumptions	-0.35	-0.55	-0.31
		Pioneer-Burdekin Pumped Hydro Project sensitivity	-0.05	-0.34	-0.09
XI (ODP)	CDP III with actionable Project Marinus Stage 2	Core assumptions	-0.50	-0.01	0.07
		Pioneer-Burdekin Pumped Hydro Project sensitivity	-0.53	-0.01	0.06

With the development of Pioneer-Burdekin Pumped Hydro Project, the benefit of early development of QNI Connect also reduces under both *Step Change* and *Progressive Change*. There is less reliance on interconnection with New South Wales for firming support, and therefore early investment in QNI Connect is not as beneficial. As a result, the regrets of progressing QNI Connect within its actionable window increase, which is seen in the worse performance of CDP VII in this sensitivity ($105 million reduction in weighted net market benefits compared to CDP III) than under core assumptions (only $20 million worse off).

Finally, CDP XI remains robust to changing assumptions, with no change to its position as the top-ranked CDP for weighted net market benefits under this sensitivity.

A6.12.8 *Development of Cethana Pumped Hydro Energy Storage*

The Cethana pumped hydro energy storage project is a key long-duration storage (750 MW, 20 hours storage duration) that is a key part of the Battery of the Nation initiative. While it is a proposed development, it is insufficiently advanced to be classified as either committed or anticipated and was instead treated as a potential build candidate in the core scenarios. This sensitivity, applied to *Step Change* only, explored the impact on the key CDPs if Cethana became an anticipated project from 2032-33.

As seen in Table 93, the assumed development of the Cethana project has no impact on relative rankings for the top five CDPs. With Cethana assumed to develop, the difference in builds and build costs in Tasmania between an early development of Project Marinus Stage 2 (CDP XI) and a delayed development of Stage 2 (CDP III) lessens, increasing the economic case for Stage 2's early development.

Table 93 Net market benefits and weighted net market benefits for key CDPs, (in $ billion) *Cethana* sensitivity and core assumptions

		With *Cethana* sensitivity			With core *Step Change*		
CDP	**CDP description**	***Step Change with Cethana* (NMB)**	**WNMB**	**WNMB rank**	***Step Change* (NMB)**	**WNMB**	**WNMB rank**
XI (ODP)	CDP III with actionable Project Marinus Stage 2	17.77	17.63	1	17.35	17.45	1
XIV	CDP III with actionable Project Marinus Stage 2 and actionable QNI Connect	17.68	17.61	2	17.25	17.42	2
III	*Step Change* least-cost DP	18.20	17.53	3	17.85	17.38	3
VIII	CDP III without actionable New England REZ Extension	18.12	17.53	4	17.78	17.38	4
VII	CDP III with actionable QNI Connect	18.13	17.51	5	17.79	17.36	5

Note: As the sensitivity analysis was implemented to CDPs beyond the top five, higher rankings may be presented.

The delivery of Project Marinus Stage 2 at an actionable timing becomes slightly less regretful with the development of Cethana, with the difference in net market benefits between CDP XI and CDP III in *Step Change* reducing from $502 million under core assumptions to $430 million in this sensitivity.

A6.12.9 The impact of cost uncertainty in the CDP collection

Since the 2022 ISP, there have been increases in capital costs for generation, storage, and transmission technologies, as detailed in the 2023 IASR, as a result of a number of factors, including global events affecting the availability and competition for relevant materials. The capital cost for these technologies, especially for the near term, has increased by as much as 35% in real dollar terms, and the accuracy of cost estimates remains uncertain.

The 2023 *Transmission Expansion Options Report*[59] shows that the accuracy range for some projects assessed in the ISP is in the order of +/-30% to +/-50%, while the cost range for generation and storage projects is estimated to be +/-30%[60].

[59] At https://aemo.com.au/-/media/files/major-publications/isp/2023/2023-transmission-expansion-options-report.pdf?la=en.

[60] See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/aurecon-2022-cost-and-technical-parameter-review.pdf?la=en.

To explore the impact of higher cost for transmission assets only (and not generation and storage), this sensitivity has been applied to all scenarios by applying the upper bound of the accuracy range for each transmission project. A sensitivity that explores the lower bound of the cost accuracy range has not been explored.

As Table 94 shows, applying the top end of the cost ranges for transmission projects has an impact on the CBA. CDP III and CDP VIII become top-ranked based on weighted net market benefits. However, because of the wider accuracy range for QNI Connect (being Class 5) than that for Project Marinus Stage 2 (being Class 4), the weighted net market benefits for CDP XI (which features Project Marinus Stage 2) is higher than the weighted net market benefits for CDP VII or CDP XIV (which features QNI Connect), with the former now ranked third in weighted net market benefits, and second in worst weighted regrets.

Table 94 Net market benefits and weighted net market benefits for key CDPs (in $ billion) with cost uplifts and core assumptions

		With transmission cost uplifts across all scenarios		With core assumptions	
CDP	**CDP description**	**WNMB rank**	**WWR rank**	**WNMB rank**	**WWR rank**
III	*Step Change* least-cost DP	1	5	3	8
VIII	CDP III without actionable New England REZ Extension	2	8	4	10
XI (ODP)	CDP III with actionable Project Marinus Stage 2	3	2	1	3
VII	CDP III with actionable QNI Connect	6	1	5	4
XIV	CDP III with actionable Project Marinus Stage 2 and actionable QNI Connect	8	7	2	1

Note: As the sensitivity analysis was implemented to CDPs beyond the top five, higher rankings may be presented.

This sensitivity sees a change in worst weighted regrets. CDP XI becomes second ranked (from third) but the regrets associated with CDP VII drops – becoming top-ranked in worst weighted regrets; and CDP XIV becoming seventh instead of first. With increased transmission costs, the regrets associated with over-investment increases and the rankings of CDPs like CDP XIV, CDP XIII and CDP I fall, whereas the rankings of those CDPs with comparatively fewer actionable projects (CDP III, CDP XI or CDP VII) increase.

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.
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.

Term	Acronym	Explanation
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.
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

Term	Acronym	Explanation
		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.
Value of greenhouse gas emissions reduction	VER	The VER estimates the value (dollar per tonne) of avoided greenhouse gas emissions. The VER is calculated consistent with the method agreed to by Australia's Energy Ministers in February 2024.
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.