Appendix 6. Cost Benefit Analysis

December 2023

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

Important notice

Purpose

This is Appendix 6 to the Draft 2024 *Integrated System Plan* (ISP) which is available at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp.

AEMO publishes the Draft 2024 ISP pursuant to its functions under section 49(2) of the National Electricity Law (which defines AEMO's functions as National Transmission Planner) and its supporting functions under the National Electricity Rules. This publication has been prepared by AEMO generally using information available at 30 October 2023. AEMO has acknowledged throughout the document where modelling has been updated to reflect the latest inputs and assumptions. Information made available after these dates has been included where practical.

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Version control

Version	Release date	Changes
1.0	15/12/2023	Initial release.

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

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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 to meet future energy needs. The ISP's optimal development path sets out the needed generation, firming and transmission, which would deliver significant net market benefits for consumers and economic opportunities in Australia's regions.

This appendix provides a detailed walkthrough of the process used in this Draft 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.

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-emission energy system while lowering cost to consumers.

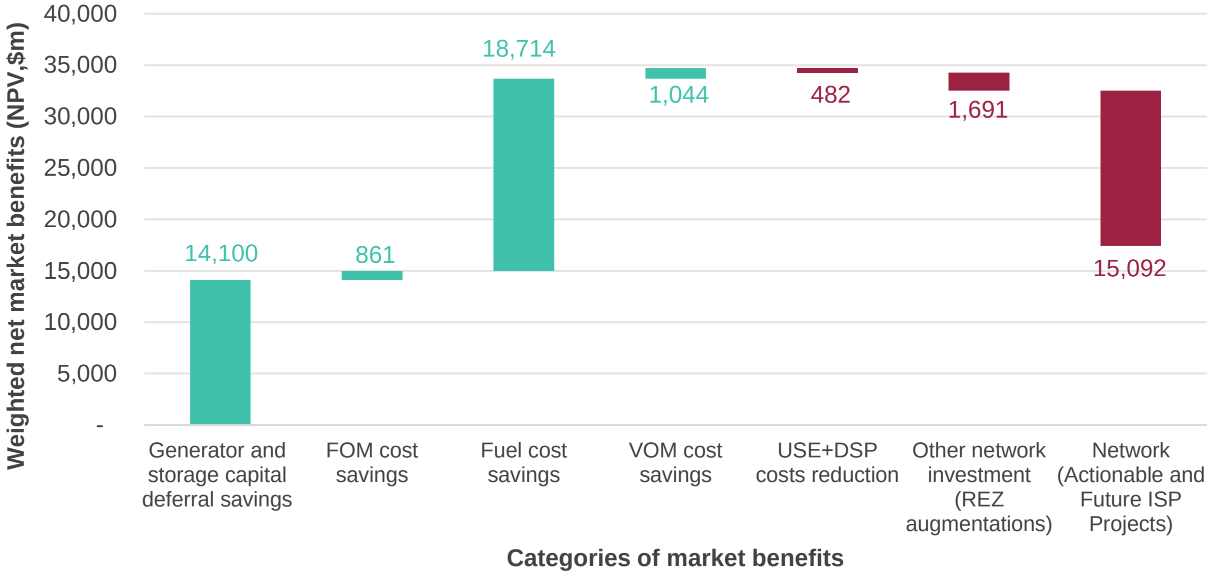
Table 1 Actionable projects in the optimal development path

Already actionable projects (confirmed in this Draft ISP as continuing to be actionable)	**In service timing advised by proponent**	**Full capacity timing advised by proponent**	**Actionable framework**
HumeLink	Northern Circuit July 2026 Southern Circuit December 2026	Northern Circuit July 2026 Southern Circuit December 2026	ISP
Sydney Ring *(Hunter Transmission Project and investigation of southern network options)*	December 2027	December 2027	NSW[A]
New England REZ Transmission Link	September 2028	September 2028	NSW[A]
Victoria – New South Wales Interconnector West (VNI West)	December 2028	December 2029	ISP
Project Marinus[B]	Stage 1 June 2030 Stage 2 June 2032	Stage 1 December 2030 Stage 2 December 2032	ISP
Newly actionable projects (as identified in this Draft ISP)	**In service timing advised by proponent**	**Full capacity timing advised by proponent**	**Actionable framework**
Gladstone Grid Reinforcement	September 2029	September 2029	QLD[C]
Queensland SuperGrid South	June 2031	June 2031	QLD[C]

Note. Details of these projects are found in Appendix 5 of this Draft 2024 ISP
A. 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. Includes additional scope compared to 2022 ISP.
B. Project Marinus includes Marinus Link as well as the North West Transmission Developments projects in Tasmania. Project proponent date represents a modelling date and is subject to further refinement.
C. These are actionable Queensland projects rather than actionable ISP projects. They are intended to progress under the *Energy (Renewable Transformation and Jobs) Bill* 2023 (Qld) rather than the ISP framework. Project proponent dates are earliest in-service dates and are subject to further refinement.

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 $17 billion. The ODP delivers balanced consideration of the risks of over- and under-investment across the scenario collection, as it is one of the highest-ranked candidates to avoid potential over- or under-investment regret.

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



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

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 sensitivities explore a range of risks and uncertainties, including:

- Alternative assumptions around consumer demand,
- Alternative assumptions around electricity supply and the potential challenges of delivery, as well as decarbonisation ambition,
- Impacts to alternative transmission developments of commitment to key strategic storage projects,
- Alternative financial assumptions regarding the annual cost of investing,
- Impact of transmission cost uncertainty.

As seen in Table 2, the ODP is one of the most resilient development paths compared with the alternatives collection. It is the path that delivers the highest-ranked weighted net market benefits across six of the ten sensitivities and second-highest in those sensitivities where it is not the highest.

Table 2 Relativity of weighted net market benefits (in $ billion) for each key CPD across the sensitivity collection

CDP	Description	Core scenarios	*Rapid Decarbonisation*	*Reduced Energy Efficiency*	*Electrification Alternatives*	*Constrained Supply Chains* A	*Reduced Social Licence*	*Higher Discount Rate*	*Lower Discount Rate*	*Development of Pioneer-Burdekin Pumped Hydro Project*	*Development of Cethana PHES*	*Transmission cost uncertainty*
Weighted net market benefits												
3	*Step Change* least-cost DP	17.38	20.69	17.40	17.16	19.36	15.73	7.66	40.25	17.13	17.53	12.31
8	CDP3 without actionable New England REZ Extension	17.38	20.67	17.39	17.19	19.37	15.75	7.71	40.20	17.11	17.53	12.23
7	CDP3 with actionable QNI Connect	17.36	20.75	17.38	17.12	19.38	15.72	7.55	40.37	17.03	17.51	12.04
11	CDP3 with actionable Project Marinus Stage 2	17.45	20.95	17.50	17.23	19.47	15.74	7.73	40.42	17.19	17.63	12.17
14	CDP3 with actionable Project Marinus Stage 2 and actionable QNI Connect	17.42	21.02	17.48	17.19	19.47	15.73	7.60	40.53	17.08	17.61	11.96
Change in weighted net market benefits relative to the most beneficial CDP												
3	*Step Change* least-cost DP	-0.07	-0.32	-0.10	-0.07	-0.11	-0.02	-0.07	-0.27	-0.08	-0.10	-
8	CDP3 without actionable New England REZ Extension	-0.07	-0.35	-0.11	-0.04	-0.10	-	-0.02	-0.33	-0.17	-0.10	-0.07
7	CDP3 with actionable QNI Connect	-0.09	-0.27	-0.12	-0.11	-0.10	-0.04	-0.17	-0.16	-	-0.12	-0.27
11	CDP3 with actionable Project Marinus Stage 2	-	-0.07	-	-	-	-0.01	-	-0.11	-0.11	-	-0.13
14	CDP3 with actionable Project Marinus Stage 2 and actionable QNI Connect	-0.04	-	-0.03	-0.04	-0.00	-0.02	-0.13	-	17.13	-0.03	-0.35

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.

Given its robust performance across the set of alternative assumptions tested, AEMO identifies CDP11 as the optimal development path.

A6.1 Introduction

Section 6 of the Draft 2024 ISP sets out the process and rationale for identifying the ODP from a range of candidate development paths (CDPs). CDPs represent a shortlist of possible alternative development paths, including each scenarios' 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 Draft 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 steps through the process of determining the least-cost DP in each scenario.
- A6.4 outlines the development of the set of CDPs based on the least-cost DPs.
- A6.5 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'.
- A6.6 summarises the findings from A6.5 and identifies the ODP.
- A6.7 tests the resilience of the ODP and a subset of the CDP collection to several sensitivities.
- A6.8 explores impact of consumer risk preferences on transmission timings.
- A6.9 finalises the identification of the ODP after considering insights from the sensitivity analyses.

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)[1] 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.

This appendix is supported by the **Generation and Storage Outlook Workbook**[2], which also provide a breakdown of the difference in system costs between CDPs.

[1] See section A6.2.1

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

Key changes from the 2022 ISP

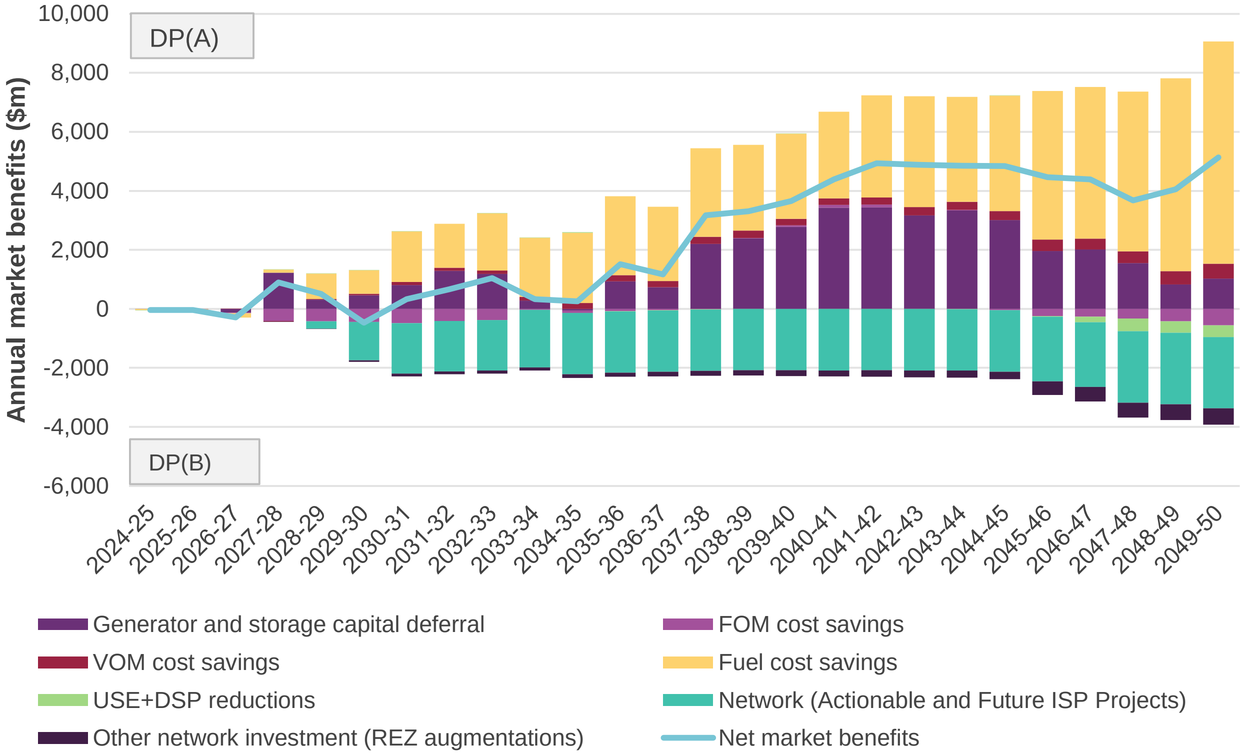
- A number of key changes in the Draft 2024 ISP have impacts in the CBA, including:
- The consulted upon and updated ISP Methodology introduced the concept of actionable windows for transmission projects. An actionable window recognises that a project identified as actionable in a previous ISP may have progressed along the transmission investment framework and satisfied certain regulatory requirements, such as the RIT-T and partial funding approval. Delaying the project in a subsequent ISP would likely 'reset' a project, require re-work of the progress made, and lead to longer lead time delays. A delay or deferral of the project therefore must be more beneficial to consumers after taking this longer period of non-delivery into account.
- Transmission, generation, and storage costs have seen varying increases; see the 2023 IASR for more detail. Transmission costs are now also forecast with scenario-specific variations, as well as varying over the outlook period.
- The Draft 2024 ISP includes a selection of REZ network augmentation projects within candidate development paths.

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 2 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 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.

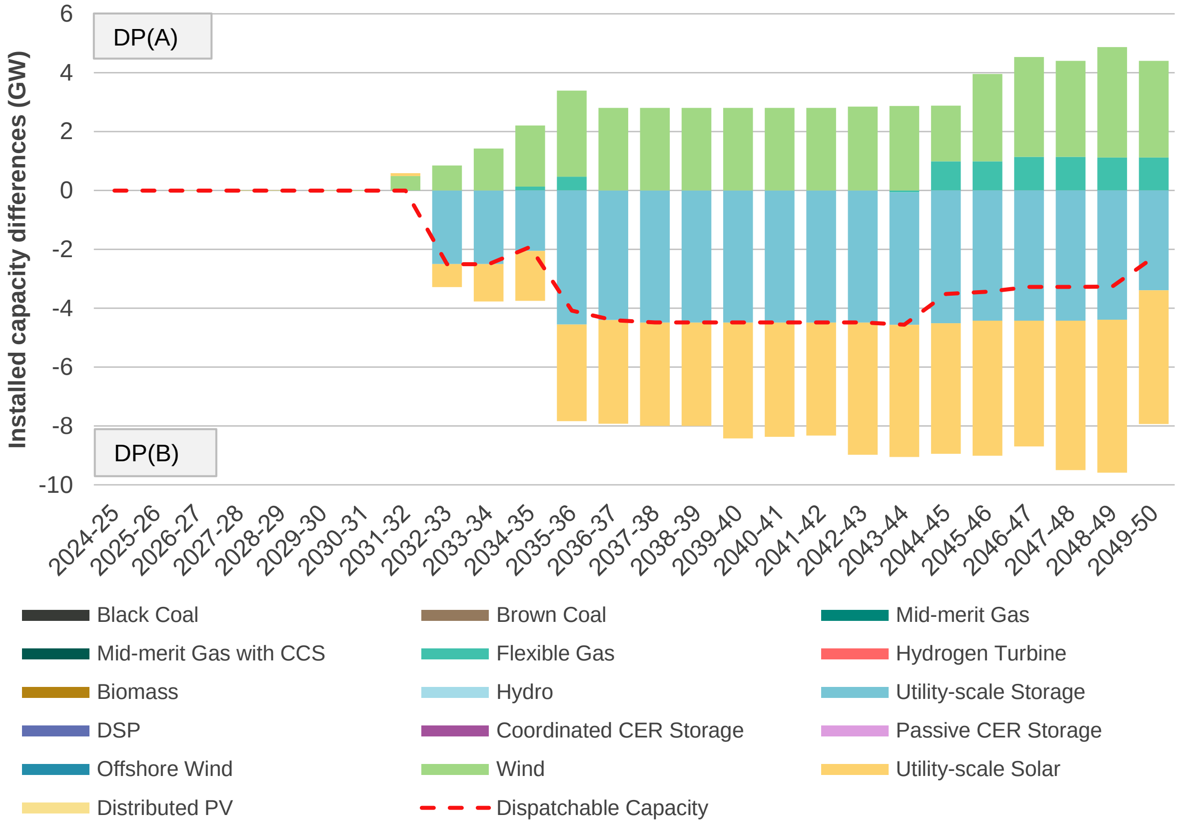
Figure 2 Example interpretation of annual market benefits used in this Appendix



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 3:

- 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-scale 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 3 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

This Draft 2024 ISP applies AEMO's *ISP Methodology*[3], 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 AER's *Forecasting Best Practice Guidelines* and *Cost Benefit Analysis Guidelines*[4]. 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[5].
- 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)[6] (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*[7] 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

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

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

[5] 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).

[6] 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.

[7] 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.

is 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 Optimal development path (ODP).
- A **minimum-regret project** is defined as being a potential actionable ISP projects 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 Candidate development path's (CDP) **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.
- 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.

Classes of market benefits

The Rules 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 DSP), and involuntary load shedding costs, valued at the value of customer reliability.

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.

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

Table 3 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 3 Scenario weightings applied in the cost-benefit analysis

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

A6.3 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[8] (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[9] 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.

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

[9] 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.

Note that capital cost figures in this Appendix are quoted for the year that the augmentation is developed in each development path. This may differ from the project cost described in Appendix 5, which quotes the latest project cost estimates from the proponent if delivered to the proponent's target delivery date or the cost on first year of the outlook period. The difference arises if a project is delayed, in which case its cost would escalates in real terms in accordance with the forecast change in transmission capital costs, as described in the 2023 Transmission Expansion Options Report.[10] Further detail on actionable and future ISP projects can be found in Appendix 5.

A6.3.1 Least-cost development path for *Step Change*

Table 4 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 Option 1 over Sydney Ring Option 2 (Alternative DP1).
- The benefits provided by QNI Connect Option 2 over the larger QNI Connect Option 5 (Alternative DP2).

Table 4 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**	2045-46	2045-46	2045-46
Queensland SuperGrid North Option 2	**2032-33**			
Gladstone Grid Reinforcement	**2030-31**	2030-31	2030-31	2030-31
Queensland SuperGrid South Option 1	**2028-29**			
Queensland SuperGrid South Option 5	**2030-31**	2030-31	2030-31	2030-31
QNI Connect Option 2	**2030-31**	2033-34	2033-34	
QNI Connect Option 5	**2032-33**			2033-34
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	**2030-31**	2030-31	2030-31	2030-31
Sydney Ring Option 1	**2027-28**	2028-29		2028-29
Sydney Ring Option 2b	**2030-31**			
Sydney Ring Option 2	**2030-31**		2030-31	
HumeLink	**2026-27**	2029-30	2029-30	2029-30
VNI West	**2029-30**	2029-30	2029-30	2029-30
Project Marinus Stage 1	**2029-30**	2029-30	2029-30	2029-30
Project Marinus Stage 2	**2031-32**	2047-48	2047-48	2047-48
Tasmanian Central Highlands REZ Upgrade	**2029-30**	2029-30	2029-30	2029-30
VIC-SESA Option 1	**2032-33**			

[10] At https://aemo.com.au/-/media/files/major-publications/isp/2023/2023-transmission-expansion-options-report.pdf.

Network option	Earliest in-service date (EISD)	Least-cost DP	Alternative DP1	Alternative DP2
Mid-North South Australia Upgrade	**2027-28**	2045-46	2045-46	2045-46
Reduction in net market benefits ($ million) compared with the least-cost DP		-	2,105	921

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

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.

Comparing options for Sydney Ring expansion

Alternative DP1 explores the potential benefits of choosing Sydney Ring Option 2 to supply the Sydney, Newcastle, and Wollongong subregion instead of Sydney Ring Option 1 which is developed in the least-cost DP for *Step Change*. Both the least-cost DP and Alternative DP1 develop the Sydney Ring augmentation at their respective EISDs.

Sydney Ring Option 1 provides an upgrade of 5,000 MW to the northern limit of the CNSW-SNW flow path and has an EISD at 2027-28 with a cost of $992 million, while Sydney Ring Option 2 provides a slightly smaller upgrade of 4,500 MW to the southern limit of the CNSW-SNW flow path but has a later EISD at 2030-31. Sydney Ring Option 2 also has a higher cost at $1699 million[11]. Sydney Ring Option 2 also has a 71% higher cost than Sydney Ring Option 1, making it 90% more expensive on a per-MW basis. The options support alternate flow paths into the major New South Wales load centre so the preferred option will be influenced by the economics of generation and storage developments north and south of Sydney.

Table 5 shows the benefits of developing Sydney Ring Option 1 instead of Sydney Ring Option 2. Most of the benefits arise from savings in deferred generator and storage capital costs fuel cost savings, as well as savings from being a cheaper augmentation option.

Table 5 Relative market benefits of the least-cost DP compared to Alternative DP1 (which has Sydney Ring Option 2 instead), *Step Change*

Class of market benefits	Relative market benefits (NPV, $ million)
Generator and storage capital deferral	935
Fixed operating and maintenance (FOM) cost savings	226
Fuel cost savings	377
VOM cost savings	24
USE+DSP reductions	39
Other network investment (REZ augmentations)	211
Gross market benefits	1,813
Network (actionable and future ISP projects)	292
Total market benefits	2,105

[11] 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.

Compared with Sydney Ring Option 2, development of Sydney Ring Option 1 would enable around 1.7 GW of additional onshore wind development in the Central New South Wales (1.1 GW in Central West Orana REZ) by 2030-31 (similar timing with the augmentation), additional utility-scale storage development in Northern New South Wales subregion (275 MW from 2027-28 and 790 MW from 2030-31), higher levels of energy flows from Queensland to Northern New South Wales, and around 1.2 GW of additional onshore wind capacity in the Darling Downs REZ from 2034-35.

Compared with Sydney Ring Option 1, development of Sydney Ring Option 2 would enable higher levels of flows from southern New South Wales into the Sydney load centre. The later development timing of Option 2 would require development of storage capacity of about 1.2 GW in Central New South Wales from 2029-30, which would be deferred with Option 1 as it would be available earlier. With Option 2, this greater storage development would increase to 2.1 GW in 2034-35 in Central New South Wales, over 2.1 GW of additional onshore wind developed in Southern New South Wales and Victoria by 2032-33, and around 1 GW of additional solar capacity in Victoria and South Australia.

Development of Sydney Ring Option 2 would also see less storage developed in the Sydney, Newcastle and Wollongong subregion from 2029-30. By 2033-34, the smaller Option 2 augmentation would need additional gas-powered generation (GPG) capacity of around 270 MW.

The net increases in storage, solar, and GPG, coupled with higher fuel costs and more expensive augmentation cost for Option 2, explains the preference for Sydney Ring Option 1.

Comparing options for QNI Connect

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 in 2033-34 with a cost of $2,756 million[12]. QNI Connect Option 2 helps support Queensland following a number of coal closures – in this scenario, all Queensland coal generators are retired by 2034-35.

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 $5,738 million in 2033-34), 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 results in generation and storage capital expenditure savings by reducing the utility-scale storage, and solar builds in Queensland.

The larger QNI Connect Option 5 improves transfer capacity from Northern New South Wales to south-west Queensland, however it does still identify new bottlenecks in transfer capacity between south-west Queensland and the south-east Queensland load centre. Full utilisation of the northerly transfer limit will at

[12] 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.

times be limited by this constraint, and an additional 1.3 GW of upgrades[13] to the Darling Downs REZ transmission network are also developed by 2035-36.

As Table 6 shows, the development of the smaller augmentation (QNI Connect Option 2) sees an overall reduction in generator capex savings amounting to $434 million. However, the lower cost of the smaller augmentation option compared with the larger QNI Connect Option 5 ($1.3 billion in net present value) results in an overall increase in relative benefits.

Table 6 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 savings	-434
FOM cost savings	-57
Fuel cost savings	62
VOM cost savings	10
USE+DSP costs reduction	5
Other network investment (REZ augmentations)	36
Gross market benefits	-379
Network (Actionable and Future ISP Projects)	1,300
Total market benefits	921

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 QRET. While Borumba Dam Pumped Hydro is 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 this project. Rather, there is increased use of southern renewable generation and firming capacity shared across the QNI Connect augmentation. In the case that the Pioneer-Burdekin Pumped Hydro Project is developed, the need for QNI Connect is delayed, as outlined in Section A6.7.7.

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

Table 7 provides a breakdown of the classes of market benefits delivered by the least-cost DP compared with the counterfactual DP, where no new transmission is developed across the NEM[14]. 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*.

[13] As discussed in the 2023 IASR, the Darling Down REZ transmission limit now accounts for flows into Queensland via QNI.

[14] 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 7 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	12,406
FOM cost savings	-2,086
Fuel cost savings	22,800
VOM cost savings	1,654
USE+DSP reductions	-406
Gross market benefits	34,367
Network (Actionable and Future ISP Projects)	-14,971
Other network investment (REZ augmentations)	-1,544
Total market benefits	17,853

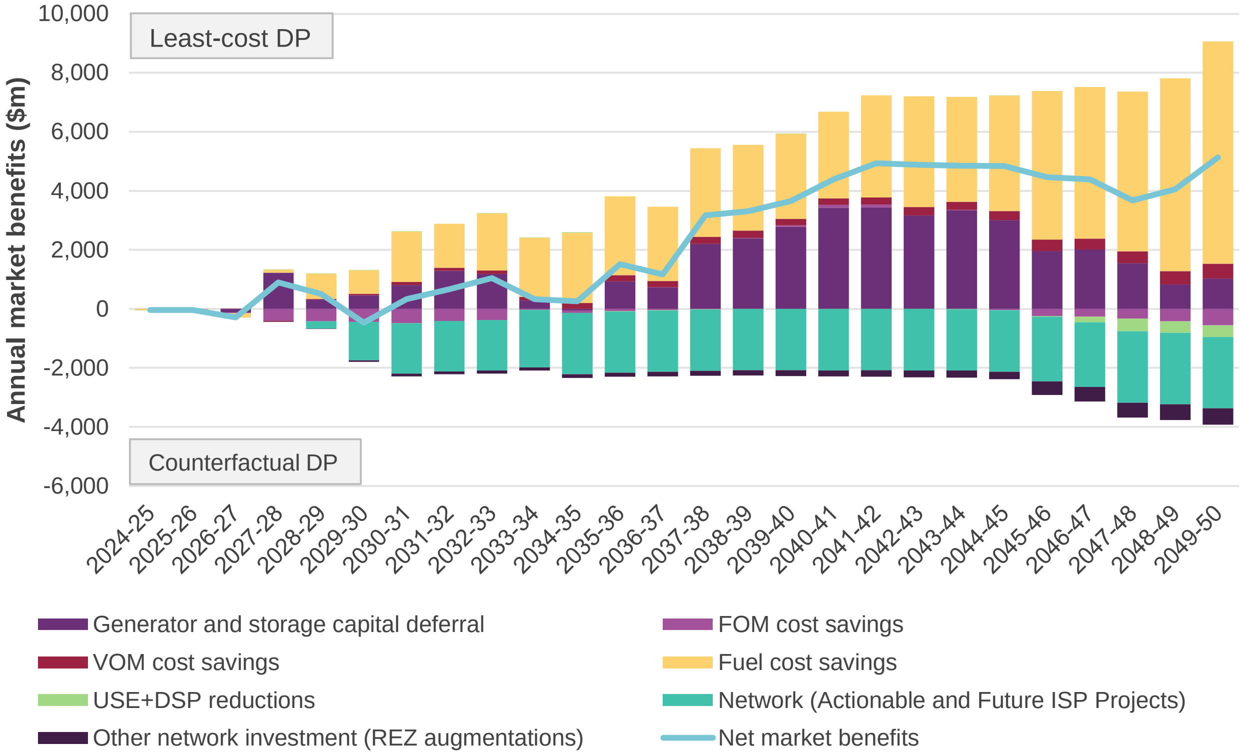
Figure 4 shows that the annual net market benefits of the least-cost DP in *Step Change* compared with the counterfactual DP take several years to emerge (when actionable ISP projects are earliest to install) and come primarily from avoided generator capital expenditure and fuel cost savings.

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 A2.3.1 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 scenario, 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. Running this flexible gas increases fuel costs and would likely require other developments in the gas supply and mid-stream infrastructure which are not considered in this analysis, including 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 are provided in Appendix 2.

Figure 4 Net market benefits of the least-cost DP relative to the counterfactual DP in *Step Change*



A6.3.2 Least-cost development path for *Progressive Change*

Table 8 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 Option 1 (Alternative DP4).

Table 8 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	**2030-31**	2030-31	2030-31	2030-31
Queensland SuperGrid South Option 1	**2028-29**			2030-31
Queensland SuperGrid South Option 5	**2030-31**	2030-31	2030-31	
QNI Connect Option 2	**2030-31**	2036-37	2036-37	2036-37
QNI Connect Option 5	**2032-33**			
New England REZ Transmission Link 1	**2028-29**	2035-36	2035-36	2035-36
New England REZ Transmission Link 2	**2032-33**	2042-43	2042-43	2042-43
New England REZ Extension	**2030-31**	2048-49	2048-49	2048-49

Network option	Earliest in-service date (EISD)	Least-cost DP	Alternative DP3	Alternative DP4
Sydney Ring Option 1	**2027-28**	2028-29	2028-29	2028-29
Sydney Ring Option 2b	**2030-31**			
Sydney Ring Option 2	**2030-31**			
HumeLink	**2026-27**	2030-31	2030-31	2030-31
VNI West	**2029-30**	2034-35	2034-35	2034-35
Project Marinus Stage 1	**2029-30**	2029-30	2029-30	2029-30
Project Marinus Stage 2	**2031-32**	2036-37		2036-37
Tasmanian Central Highlands REZ Upgrade	**2029-30**	2029-30	2029-30	2029-30
VIC-SESA Option 1	**2032-33**			
Mid-North South Australia Upgrade	**2027-28**	2050-51	2050-51	2050-51
Reduction in net market benefits ($ million) compared with the least-cost DP		-	187	1,790

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

Project Marinus Stage 2 provides additional transfer capacity of 750 MW in both directions with a cost of $2,723 million in 2036-37[15].

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 fuel costs savings which amount to approximately $938 million in NPV over the outlook period.

Table 9 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	176
FOM cost savings	16
Fuel cost savings	938
VOM cost savings	8
USE+DSP reductions	-3
Other network investment (REZ augmentations)	-65
Gross market benefits	1,069
Network (Actionable and Future ISP Projects)	-882
Total market benefits	187

[15] 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.

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 has the effect of producing 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 additional VRE in the mainland from the mid-2030s and medium-depth storage and GPG.

These differences in capacity expansion lead to savings amounting to $187 million in NPV with Project Marinus Stage 2.

Comparing options for 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, Queensland SuperGrid South Option 5 is developed in at its EISD and in Alternative DP4, Queensland SuperGrid South Option 1 is also developed at the same timing as Queensland SuperGrid South Option 5 (2030-31). 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 $3,534 million in 2030-31. 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), with a cost of $882 million in 2030-31[16].

As Table 10 shows, 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 costs savings of around $1.2 billion. Overall, the larger option results in higher net market benefits of $1.8 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 10 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 savings	1,887
FOM cost savings	163
Fuel cost savings	1,206
VOM cost savings	64
USE+DSP costs reduction	-2
Other network investment (REZ augmentations)	-18
Gross market benefits	3,301
Network (Actionable and Future ISP Projects)	-1,510
Total market benefits	1,790

[16] 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.

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 delivered allows less firming investment in GPG capacities in South Queensland required. Additionally, the augmentation avoids higher fuel costs associated with GPG that would otherwise require to operate more frequently, and it improves the utilisation of utility-scale solar in Queensland – mainly in the Wide Bay and Darling Down REZs.

In developing the larger Option 5 augmentation, approximately 1 GW of alternative medium-depth and deep storage investment in Central Queensland can be avoided.

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

Table 11 provides a breakdown of the classes of market benefits delivered by the least-cost DP in *Progressive Change* compared with the counterfactual DP[17]. Generator capital costs and fuel cost savings each represent roughly half of the gross market benefits of the least-cost DP in *Progressive Change*.

Table 11 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	10,490
FOM cost savings	1,324
Fuel cost savings	9,246
VOM cost savings	186
USE+DSP reductions	8
Gross market benefits	21,254
Network (Actionable and Future ISP Projects)	-12,931
Other network investment (REZ augmentations)	-684
Total market benefits	7,639

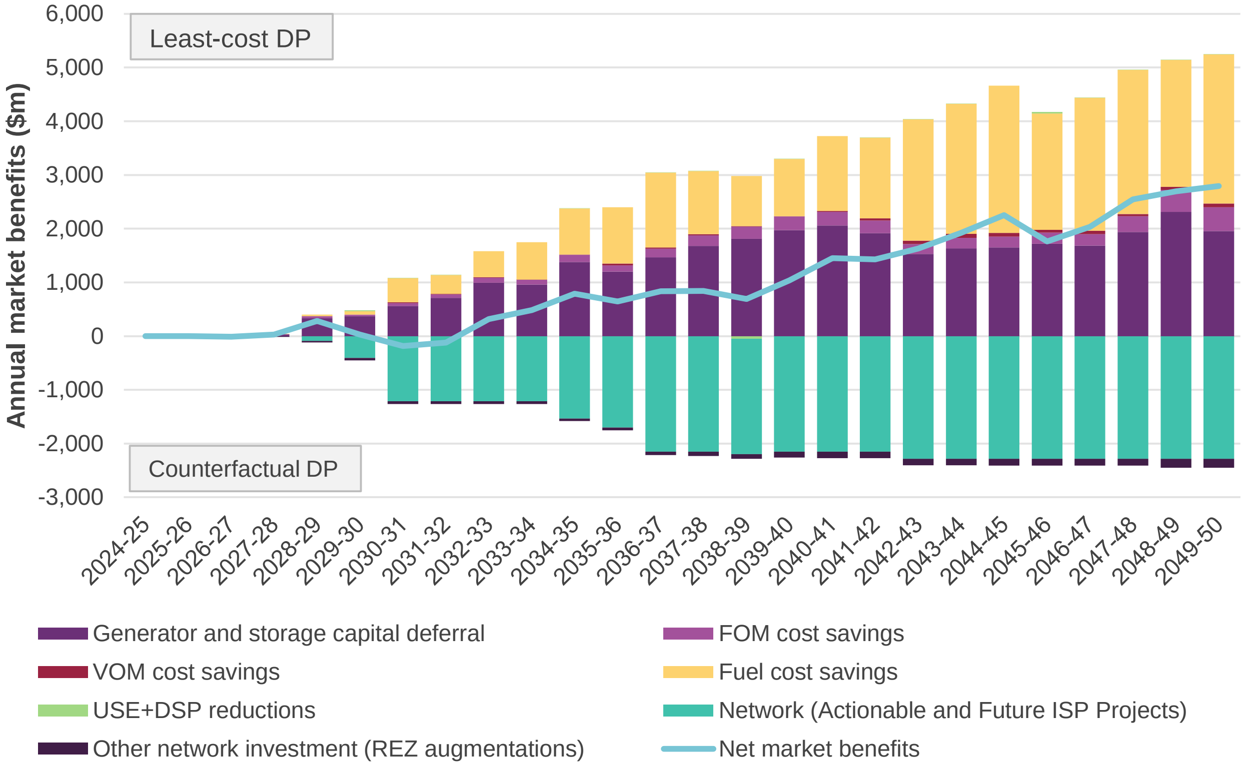
Figure 5 shows that the annual net market benefits of the least-cost DP in *Progressive Change* arise initially from both fuel cost and generator and storage capital deferral. While these benefits grow rapidly from 2035-36, the transmission development costs in the least-cost DP also increase.

Without transmission investment, the counterfactual DP relies on the development of GPG (around 3 GW from 2032-33), pumped hydro (2.8 GW from 2035-36), and utility-scale solar capacity from 2030-31. The increasing GPG capacity results in greater fuel costs, which grow in particular from the mid-2030s. By 2042-43 avoiding these fuel costs represents the largest component of net benefit for the least-cost DP, avoiding relatively 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.

[17] 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.

Figure 5 Net market benefits of the least-cost DP relative to the counterfactual DP in *Progressive Change*



A6.3.3 Least-cost development path for *Green Energy Exports*

Table 12 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 an additional augmentation to the Sydney, Newcastle, and Wollongong subregion (Alternative DP6), given the higher growth forecast in the *Green Energy Exports* scenario.

Table 12 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**	2044-45	2044-45	2044-45
Gladstone Grid Reinforcement	**2030-31**	2030-31	2030-31	2030-31
Queensland SuperGrid South Option 1	**2028-29**			
Queensland SuperGrid South Option 5	**2030-31**	2030-31	2030-31	2030-31
QNI Connect Option 2	**2030-31**	2030-31	2030-31	2030-31
QNI Connect Option 5	**2032-33**	2044-45	2044-45	2044-45
New England REZ Transmission Link 1	**2028-29**	2028-29	2028-29	2028-29
New England REZ Transmission Link 2	**2032-33**[A]	2028-29	2028-29	2028-29
New England REZ Extension	**2030-31**	2030-31	2030-31	2030-31
Sydney Ring Option 1	**2027-28**	2027-28	2027-28	2027-28
Sydney Ring Option 2b	**2030-31**	2040-41	2040-41	
Sydney Ring Option 2	**2030-31**			
HumeLink	**2026-27**	2029-30	2029-30	2029-30
VNI West	**2029-30**	2030-31	2030-31	2030-31
Project Marinus Stage 1	**2029-30**	2029-30	2029-30	2029-30
Project Marinus Stage 2	**2031-32**	2031-32	2031-32	2031-32
Tasmanian Central Highlands REZ Upgrade	**2029-30**	2029-30	2029-30	2029-30
VIC-SESA Option 1	**2032-33**		2032-33	
Mid-North South Australia Upgrade	**2027-28**	2028-29	2028-29	2028-29
Reduction in net market benefits ($ million) compared with the least-cost DP		-	-435	83

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
A. This project was modelled earlier than its EISD in *Green Energy Exports*. While it is not expected to materially impact the conclusions of this analysis, this will be rectified in the final 2024 ISP.

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.

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 to export green energy 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[18].

[18] 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 13 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 develop 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 310 MW of additional wind capacity is developed in South East South Australia by 2039-40 under Alternative DP5 compared with the least-cost DP, and most of the energy produced from that new VRE capacity is to be transported to Victoria as there is not much demand in South East South Australia. Despite the additional network capacity, there is not much need to develop VRE in South East South Australia as developments in Victorian offshore wind capacity (driven by government policy) is sufficient and therefore limits the value of the augmentation, which reduces relative market benefits by almost $435 million in this scenario.

Table 13 Relative market benefits of Alternative DP5 (which includes VIC-SESA Option 1) compared to the least-cost DP, *Green Energy Exports*

Class of market benefits	Relative market benefits (NPV, $ million)
Generator and storage capital deferral	-15
FOM cost savings	11
Fuel cost savings	-8
VOM cost savings	-1
USE+DSP reductions	39
Other network investment (REZ augmentations)	6
Gross market benefits	32
Network (Actionable and Future ISP Projects)	-468
Total market benefits	-435

Benefits of additional augmentation to Sydney, Newcastle, and Wollongong

The least-cost DP for *Green Energy Exports* develops multiple Sydney Ring augmentations to provide adequate supply to the Sydney, Newcastle, and Wollongong subregion as demand increases throughout the outlook period. Sydney Ring Option 1 is initially required in 2027-28 while Sydney Ring Option 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 $648 million[19].

Alternative DP6 evaluates the impact on total system costs of not developing Sydney Ring 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 presented in Table 14, demonstrating that developing this expanded Sydney Ring augmentation as a future project results in an overall increase in relative market benefits of almost $83 million.

The main driver of these benefits is to avoid the need for flexible gas investment (200MW) in the Sydney, Newcastle, and Wollongong subregion, as well as 800 MW of additional wind capacity across Central New South Wales in the 2040s. The augmentation strengthens the peak supply capability to the major load centre, reducing the potential need for DSP utilisation throughout the 2040s as well.

[19] 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 14 Relative market benefits of the least-cost DP compared to Alternative DP6 (which does not include Sydney Ring Option 2b), *Green Energy Exports*

Class of market benefits	Relative market benefits (NPV, $ million)
Generator and storage capital deferral	156
FOM cost savings	27
Fuel cost savings	-1
VOM cost savings	-1
USE+DSP reductions	48
Other network investment (REZ augmentations)	-12
Gross market benefits	218
Network (Actionable and Future ISP Projects)	-134
Total market benefits	83

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

While the counterfactual DP typically does not allow for 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 15 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 15 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 savings	32,651
FOM cost savings	8,518
Fuel cost savings	32,089
VOM cost savings	1,592
USE+DSP costs reduction	-2,288
Gross market benefits	72,563
Network (Actionable and Future ISP Projects)	-19,292
Other network investment (REZ augmentations)	-4,735
Total market benefits	48,536

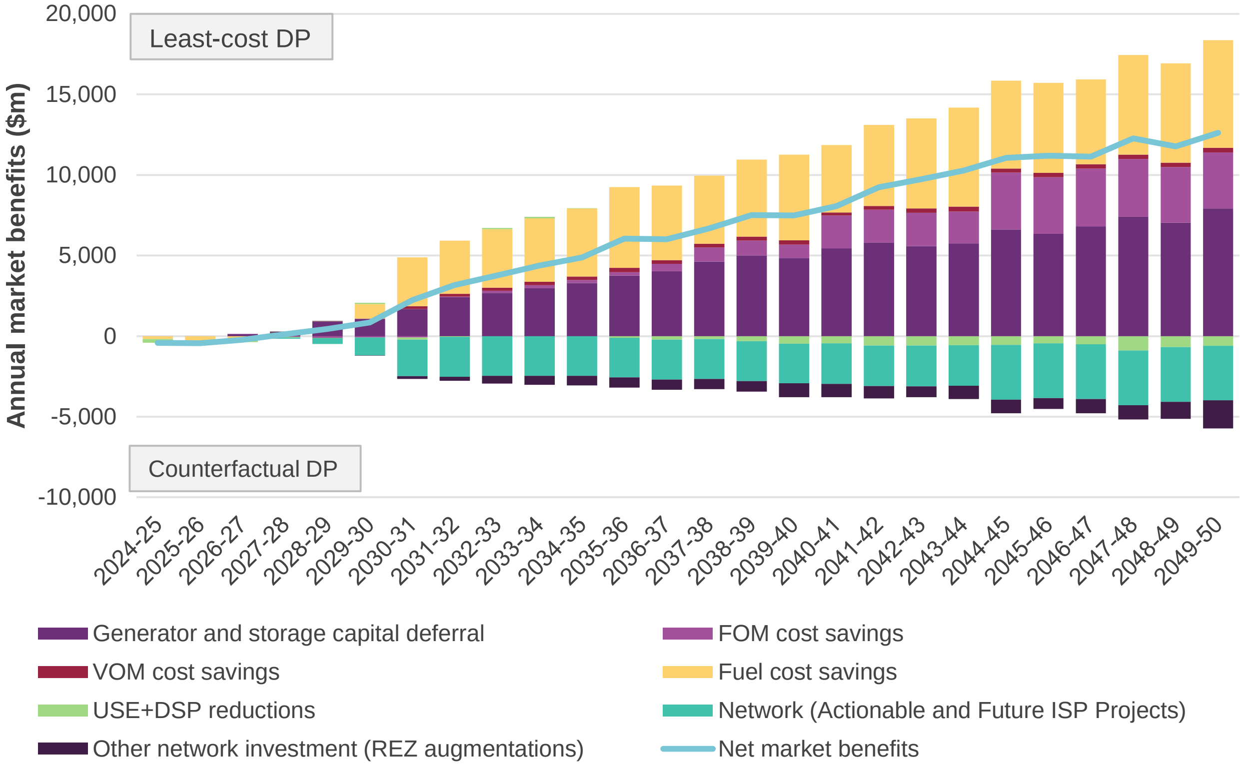
Figure 6 presents the annual net market benefits of the least-cost DP in *Green Energy Exports*. Benefits begin to accrue relatively quickly, as transmission assets are developed from 2027-28, reducing the need for alternative generator capital investment. Without transmission investment, the cost of 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).

To continue to supply a growing NEM with limited renewable generation options, the counterfactual DP starts to invest in flexible gas with CCS from 2030-31[20]. 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.

Figure 6 Net market benefits of the least-cost DP relative to the counterfactual DP in *Green Energy Exports*



A6.3.4 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 emission 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.

[20] 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.

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 Draft 2024 ISP are assumed to increase over the outlook period in real terms.
- Increase in 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, 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 Draft 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.

As further detailed in Appendix 5, in *Step Change* approximately 5,000 km of transmission in the next decade, about half of which is already underway as committed or anticipated projects. Around 10,000 km is needed by 2050. *Progressive Change* follows a similar albeit slightly delayed 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 over 25,000 kilometres of new transmission network investments by 2049-50.

Table 16 Comparing the least-cost DPs between scenarios

Network options	Earliest in-service date (EISD)	*Step Change*	*Progressive Change*	*Green Energy Exports*
Queensland SuperGrid North Option 1	**2030-31**	2045-46		2030-31
Queensland SuperGrid North Option 2	**2032-33**			2044-45
Gladstone Grid Reinforcement	**2030-31**	2030-31	2030-31	2030-31
Queensland SuperGrid South Option 1	**2028-29**			2030-31
Queensland SuperGrid South Option 5	**2030-31**	2030-31	2030-31	2030-31
QNI Connect Option 2	**2030-31**	2033-34	2036-37	2030-31
QNI Connect Option 5	**2032-33**			2044-45
New England REZ Transmission Link 1	**2028-29**	2028-29	2035-36	2028-29
New England REZ Transmission Link 2	**2032-33[A]**	2034-35	2042-43	2028-29
New England REZ Extension	**2030-31**	2030-31	2048-49	2030-31
Sydney Ring Option 1	**2027-28**	2028-29	2028-29	2027-28
Sydney Ring Option 2	**2030-31**			2040-41
HumeLink	**2026-27**	2029-30	2030-31	2029-30
VNI West	**2029-30**	2029-30	2034-35	2030-31
Project Marinus Stage 1	**2029-30**	2029-30	2029-30	2029-30
Project Marinus Stage 2	**2031-32**	2047-48	2036-37	2031-32
Tasmanian Central Highlands REZ Upgrade	**2029-30**	2029-30	2029-30	2029-30

Network options	Earliest in-service date (EISD)	*Step Change*	*Progressive Change*	*Green Energy Exports*
Mid-North South Australia Upgrade	**2027-28**	2045-46	2050-51	2028-29

Note: Teal-coloured text highlights those projects that are delivered at their EISDs.
A. This project was modelled earlier than its EISD in *Green Energy Exports*. While it is not expected to materially impact the conclusions of this analysis, this will be rectified in the final 2024 ISP.

A6.3.5 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 17 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.

Table 17 Potentially actionable projects in the *Draft 2024 ISP*

Network options	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	All scenarios	2030-31	2	2031-32
Queensland SuperGrid South Option 5	All scenarios	2030-31	2	2031-32
QNI Connect Option 2	*Green Energy Exports*	2030-31	2	2031-32
New England REZ Transmission Link 1	*Step Change, Green Energy Exports*	2028-29	4	2031-32
New England REZ Transmission Link 2	*Green Energy Exports*	2032-33[B]	2	2033-34
New England REZ Extension	*Step Change, Green Energy Exports*	2030-31	2	2031-32
Sydney Ring Option 1	All scenarios	2027-28	4	2030-31
HumeLink	All scenarios	2026-27	6	2033-32
VNI West	All scenarios	2029-30	6	2034-35
Project Marinus Stage 1	All scenarios	2029-30	6	2036-35
Project Marinus Stage 2	*Progressive Change, Green Energy Exports*	2031-32	6	2036-37
Tasmanian Central Highlands REZ Upgrade	All scenarios	2029-30	2	2030-31
Mid-North South Australia Upgrade	*Green Energy Exports*	2027-28	2	2028-29

A. Actionable window is always inclusive of the EISD.
B. This project was modelled earlier than its EISD in *Green Energy Exports*. While it is not expected to materially impact the conclusions of this analysis, this will be rectified in the final 2024 ISP.

See Appendix 5 for more information on network investments.

A6.4 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 DPs 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 Draft 2024 ISP are shown in Table 18, 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 A6.5.

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.
- CDP2, which is based on *Progressive Change*'s least-cost DP.
- CDP3, which is based on *Step Change's* least-cost DP.

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

- CDP7, which moves QNI Connect to within its actionable window in contrast with the *Step Change* least-cost DP (CDP3), given the project is developed within its actionable window in CDP1.
- CDP9, which moves Queensland SuperGrid North to within its actionable window in contrast with the *Step Change* least-cost DP (CDP3), given the project is developed within its actionable window in CDP1.
- CDP10, which moves Mid-North South Australia Upgrade to within its actionable window in contrast with the *Step Change* least-cost DP (CDP3), given the project is developed within its actionable window in CDP1.
- CDP11, which moves Project Marinus Stage 2 to within its actionable window in contrast with the *Step Change* least-cost DP (CDP3), given the project is developed within its actionable window in CDP1.
- CDP13, which moves both Project Marinus Stage 2 and Mid-North South Australia Upgrade to within their actionable windows in contrast with the *Step Change* least-cost DP (CDP3), given the projects are developed within their actionable windows in CDP1.
- CDP14, which moves both QNI Connect and Project Marinus Stage 2 to within their actionable windows in contrast with the *Step Change* least-cost DP (CDP3), given the projects are both developed within their actionable window in CDP1.

To explore later timing of investments, the following CDPs were created:

- CDP4, which moves Sydney Ring to outside its actionable window in contrast with the *Step Change* least-cost DP (CDP3).

- CDP5, which moves HumeLink to outside its actionable window in contrast with the *Step Change* least-cost DP (CDP3).
- CDP6, which moves VNI West to outside its actionable window in contrast with the *Step Change* least-cost DP (CDP3).
- CDP8, which moves the New England REZ Extension to outside its actionable window in contrast with the *Step Change* least-cost DP (CDP3).
- CDP12, which moves Project Marinus Stage 1 to outside its actionable window in contrast with the *Step Change* least-cost DP (CDP3).
- CDP15, which moves Queensland SuperGrid South to outside its actionable window in contrast with the *Step Change* least-cost DP (CDP3).
- CDP16, which moves Queensland SuperGrid South and Gladstone Grid Reinforcement to outside their actionable windows in contrast with the *Step Change* least-cost DP (CDP3). As Gladstone Grid is a pre-requisite to Queensland SuperGrid South Option 5, both need delaying beyond the actionable window.
- CDP17 delays all projects to outside their actionable windows.

Table 18 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**	**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															
1	*Green Energy Exports* least-cost	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
2	*Progressive Change* least-cost		✓	✓					✓	✓	✓	✓	✓	✓	
3	*Step Change* least-cost		✓	✓		✓		✓	✓	✓	✓	✓		✓	
Testing alternatives timings based on CDP3															
4	CDP3 without actionable Sydney Ring		✓	✓		✓		✓		✓	✓	✓		✓	
5	CDP3 without actionable HumeLink		✓	✓		✓		✓	✓		✓	✓		✓	
6	CDP3 without actionable VNI West		✓	✓		✓		✓	✓	✓		✓		✓	
7	CDP3 with actionable QNI Connect		✓	✓	✓	✓		✓	✓	✓	✓	✓		✓	
8	CDP3 without actionable New England REZ Extension		✓	✓		✓			✓	✓	✓	✓		✓	
9	CDP3 with actionable Queensland SuperGrid North	✓	✓	✓		✓		✓	✓	✓	✓	✓		✓	
10	CDP3 with actionable Mid-North South Australia Upgrade		✓	✓		✓		✓	✓	✓	✓	✓		✓	✓
11	CDP3 with actionable Project Marinus Stage 2		✓	✓		✓		✓	✓	✓	✓	✓	✓	✓	
12	CDP3 without actionable Project Marinus Stage 1		✓	✓		✓		✓	✓	✓	✓			✓	
13	CDP3 with actionable Project Marinus Stage 2 and Mid-North South Australia Upgrade		✓	✓		✓		✓	✓	✓	✓	✓	✓	✓	✓
14	CDP3 with actionable Project Marinus Stage 2 and QNI Connect		✓	✓	✓	✓		✓	✓	✓	✓	✓	✓	✓	
15	CDP3 without actionable Queensland SuperGrid South		✓			✓		✓	✓	✓	✓	✓		✓	
16	CDP3 without actionable Queensland SuperGrid South and Gladstone Grid Reinforcement					✓		✓	✓	✓	✓	✓		✓	
Testing a CDP with no actionable projects															
17	**No actionable projects**														

Table 19 shows similar information in a different view.

Table 19 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		Sydney Ring
CDP5		HumeLink
CDP6		VNI West
CDP7	QNI Connect	
CDP8		New England REZ Extension
CDP9	Queensland SuperGrid Northern	
CDP10	Mid-North South Australia Upgrade	
CDP11	Project Marinus Stage 2	
CDP12		Project Marinus Stage 1
CDP13	Project Marinus Stage 2 and Mid-North South Australia Upgrade	
CDP14	Project Marinus Stage 2 and QNI Connect	
CDP15		Queensland SuperGrid South
CDP16		Queensland SuperGrid South and Gladstone Grid Reinforcement
CDP17		No actionable projects (all delayed to outside their actionable windows)

A. See Table 18 above.

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

A6.5.1 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 A6.7). 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 20 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 20 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
11	17.35	7.24	46.35	17.45	1	0.33	3
14	17.25	7.06	46.93	17.42	2	0.26	1
3	17.85	7.25	44.41	17.38	3	0.62	8
8	17.78	7.44	44.10	17.38	4	0.66	10
7	17.79	7.07	44.97	17.36	5	0.53	4
15	17.69	7.43	44.21	17.36	6	0.65	9
13	17.22	6.99	46.50	17.31	7	0.31	2
10	17.73	6.99	44.52	17.24	8	0.60	7
16	17.57	7.55	43.39	17.24	9	0.77	13
9	17.50	6.70	44.90	17.07	10	0.55	5
6	17.60	7.08	43.44	17.06	11	0.76	12
2	16.59	7.64	44.57	17.03	12	0.60	6
1	17.11	5.68	48.54	17.02	13	0.82	14
4	17.41	6.86	43.84	16.94	14	0.70	11
12	17.61	6.24	42.64	16.59	15	0.88	15
5	17.11	6.76	41.55	16.43	16	1.05	16
17	15.14	5.90	34.74	14.20	17	2.07	17

The table above highlights that the majority of CDPs deliver over $17 billion NPV of net market benefits in the most-likely *Step Change* scenario and when weighted across the three scenarios.

The top five CDPs ranked using the weighted net market benefits approach (Approach A) share a number of common potential actionable projects, such as New England REZ Transmission Link, Sydney Ring, HumeLink, Project Marinus Stage 1, Tasmanian Central Highlands REZ Upgrade, Queensland SuperGrid South, VNI West, and Gladstone Grid Reinforcement. These CDPs differ in the actionable status of Project Marinus Stage 2, QNI Connect, and New England REZ Extension.

A6.5.2 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. Projects that are found to be optimal if developed within their actionable windows across all scenarios (such as Gladstone Grid Reinforcement and Queensland SuperGrid South) are not discussed.

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 (unless otherwise stated) 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 Draft 2024 ISP, this has been assessed using CDP3 (the least-cost DP for *Step Change*). The final 2024 ISP will implement the TOOT analysis using the project timing in the ODP, see the ISP Methodology[21] for further details. 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 *Draft 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*).

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[22]. Under all scenarios in the Draft 2024 ISP, delivery of HumeLink within its actionable window is found to be optimal, ranging from 2029-30 in *Step Change* and *Green Energy Exports* to 2030-31 in *Progressive Change* – all

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

[22] 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.

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 21 and Figure 7 highlight the relative market benefits that HumeLink provides at the *Step Change's* least-cost DP's timing, 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 GPG over the outlook period. Greater access to Snowy 2.0 avoids more expensive GPG 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 billion of the $17.85 billion net market benefits in *Step Change*.

Table 21 Relative market benefits of HumeLink in *Step Change*

Class of market benefits	Relative market benefits (NPV, $ million)
Generator and storage capital deferral savings	3,249
FOM cost savings	359
Fuel cost savings	480
VOM cost savings	27
USE+DSP costs reduction	27
Other network investment (REZ augmentations)	39
Gross market benefits	4,180
Network (actionable and future ISP projects)	-3,111
Total market benefits	1,069

Figure 7 Annual relative market benefits of HumeLink in *Step Change*

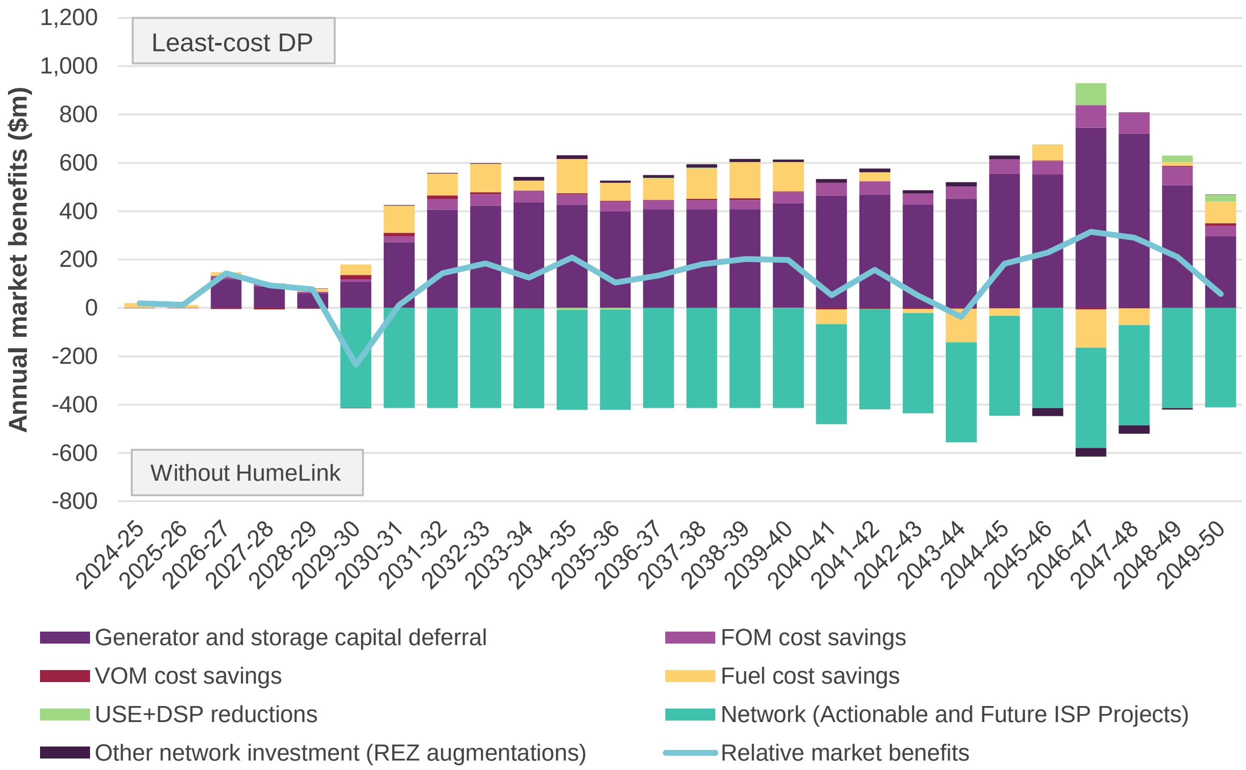
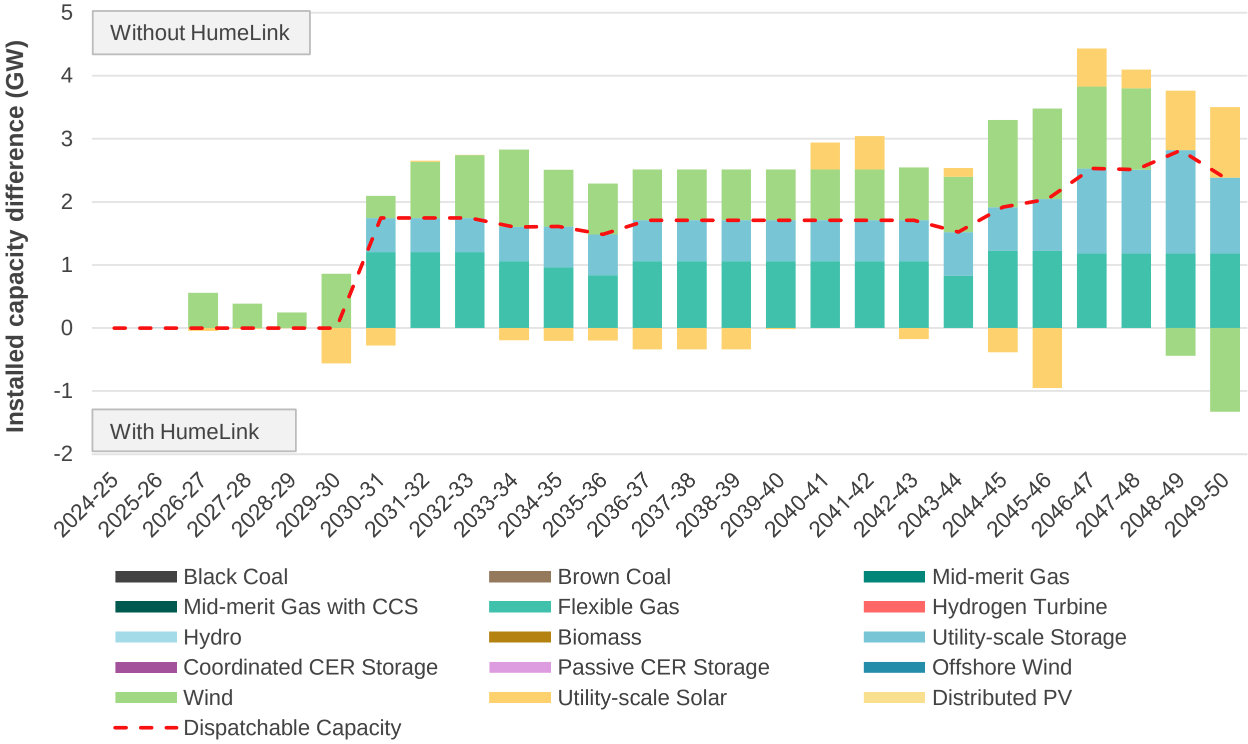


Figure 8 shows that replacing retired coal capacity and meeting increasing demands in the absence of HumeLink requires more capacity development during the first half of the 2030s. Without HumeLink, 1.2 GW of GPG in the Sydney, Newcastle, and Wollongong subregion, approximately 500 MW of pumped hydro in Northern New South Wales, and 1.2 GW of onshore wind in Central New South Wales and Queensland are required from 2026-27 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.

This is different to the result of the 2022 ISP, where utility-scale storage instead was found to be the next best alternative to an actionable HumeLink. The change in findings is mainly attributable to the increase in capital costs for batteries relative to GPG compared to the assumptions that underpinned the 2022 ISP. Gas prices have also decreased in this 2024 ISP, compared to the 2022 ISP. Assumptions around the firm capacity of batteries have also been revised down to consider the longer duration of USE events found in the 2023 ESOO. See Section 2.4.3 of the *ISP Methodology* for further details on how these assumptions are derived and used.

Figure 8 Comparison of capacity with and without HumeLink in *Step Change* (2029-30)



Assessing the net market benefits of HumeLink as an actionable project

In this 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 $491 million in *Progressive Change* to $2.86 billion in *Green Energy Exports*, see Table 22. The biggest driver for the greater and earlier need to deliver HumeLink is the inclusion of several policies such as the Powering Australia Plan which targets 82% VRE by 2030 and the tighter carbon budget which further limits coal generation. These two 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 from 2031-32 (which increases the amount of potential surplus energy generation in Victoria at times).

Table 22 compares the net market benefits of CDP3 and CDP5, 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 $953 million.

Table 22 Comparing net market benefits between CDP3 and CDP5 ($ billion) – HumeLink

	CDP3 – with actionable HumeLink	CDP5 – without actionable HumeLink	Change in net market benefits associated with not actioning the project[A]
Step Change	17.85	17.11	-0.74
Progressive Change	7.25	6.76	-0.49
Green Energy Exports	44.41	41.55	-2.86
Weighted net market benefits	17.38	16.43	-0.95

	CDP3 – with actionable HumeLink	CDP5 – without actionable HumeLink	Change in net market benefits associated with not actioning the project[A]
Ranking based on weighted net market benefits	3	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.

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 GPG 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 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, leading to a commensurate deferral, which results in further benefits being accrued in CDP3 compared to CDP5 due to further deferral of generation capital costs.

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 CDP5 in terms of weighted regrets. As seen in Table 23, the highest regrets for both CDP3 and CDP5 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 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 path that are more costly.

Continuing with HumeLink as an actionable project decreases the regrets across all scenarios, which then reduces worst weighted regrets by $430 million.

Table 23 Weighted and worst weighted regrets of CDP3 and CDP5 ($ billion) – HumeLink

	CDP3 – with actionable HumeLink	CDP5 – without actionable HumeLink	Change in weighted regrets associated with not actioning the project[A]
Step Change	0.00	0.32	0.32
Progressive Change	0.16	0.37	0.21
Green Energy Exports	0.62	1.05	0.43
Worst weighted regrets	0.62	1.05	0.43
Ranking based on worst weighted regrets	8	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.

VNI West

Like HumeLink, since 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 capacity augmentation of 1,935 MW towards New South Wales and 1,669 towards Victoria at a cost of $3,870 million in 2029-30[23]. Every scenario's least-cost DP finds VNI West as preferable to develop within its actionable window, with varying optimal 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 across all scenarios, particularly 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 from surplus Victorian energy once offshore wind is developed to scale. 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 24 highlights the relative market benefits that VNI West provides in *Step Change*'s least-cost DP's timing compared to a case without it. These benefits result mainly from generator and storage capital deferral and to a lesser extent, fuel costs savings. Overall, VNI West contributes roughly $0.7 billion of the $17.85 billion net market benefits in *Step Change*.

Table 24 Relative market benefits of VNI West in *Step Change*

Class of market benefits	Relative market benefits (NPV, $ million)
Generator and storage capital deferral savings	2,583
FOM cost savings	198
Fuel cost savings	268
VOM cost savings	-5
USE+DSP costs reduction	88
Other network investment (REZ augmentations)	-6
Gross market benefits	3,126
Network (Actionable and Future ISP Projects)	-2,422
Total market benefits	704

The main source of benefits arises from developing VNI West within its actionable window is from avoided capital expenditure of shifting around 1.3 GW of storage capacity from deep to shallow depth, around 900 MW of avoided GPG, and 600 MW of avoided solar in Victoria (particularly when the last brown coal units retire).

[23] 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.

Additionally, if VNI West is built at its optimal timing in *Step Change*, there may be an opportunity for Victoria's storage target to be met by lower cost shallow storage, rather than deeper options that would be more appropriate without improved access to capacity to the north.

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 CDP6 (which delays VNI West to outside its actionable window – no earlier than 2035-36). As Table 25 shows, an actionable VNI West delivers $326 million in weighted net market benefits.

Table 25 Comparing net market benefits between CDP3 and CDP6 ($ billion) – VNI West

	CDP3 – with actionable VNI West	CDP6 – without actionable VNI West	Change in net market benefits associated with not actioning the project[A]
Step Change	17.85	17.60	-0.25
Progressive Change	7.25	7.08	-0.17
Green Energy Exports	44.41	43.44	-0.97
Weighted net market benefits	17.38	17.06	-0.33
Ranking based on weighted net market benefits	3	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.

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, it has similar impacts to alternative generation and storage developments as was described earlier when the project was not developed. That is, by delaying the project there are greater needs for firming capacity through deeper storages and GPG in Victoria and neighbouring regions.

Assessing the regrets associated with VNI West as an actionable project

As Table 26 shows, delaying VNI West until after its actionable window increases regrets across all scenarios, and results in an increase in worst weighted regrets by $146 million. The worst weighted regrets come from the risks resulting from under-investing in VNI West under the *Green Energy Exports* scenario. 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 increased capacity to share resources when needed with Victoria. This is a similar need to that identified in the 2022 ISP.

Table 26 Weighted and worst weighted regrets of CDP3 and CDP6 ($ billion) – VNI West

	CDP3 – with actionable VNI West	CDP6 – without actionable VNI West	Change in weighted regrets associated with not actioning the project[A]
Step Change	0.00	0.11	0.11
Progressive Change	0.16	0.23	0.07
Green Energy Exports	0.62	0.76	0.15

	CDP3 – with actionable VNI West	CDP6 – without actionable VNI West	Change in weighted regrets associated with not actioning the project[A]
Worst weighted regrets	0.62	0.76	0.15
Ranking based on worst weighted regrets	8	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.

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 – the development of the first and second cables are Stage 1 and Stage 2, respectively. Stage 1 and Stage 2 each see an increase of network capacity of 750 MW between Victoria and Tasmania, at a cost of $3,851 million in 2029-30 and $2,781 million in 2047-48 respectively[24].

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 (2029-30 for Stage 1 and 2031-32 for Stage 2), Project Marinus Stage 1 would be actionable if its optimal timing takes place before or in 2034-35 and Project Marinus Stage 2 before or in 2036-37.

Every scenario's least-cost DP finds the delivery of Project Marinus Stage 1 to be optimal at its EISD (2029-30). Development of Project Marinus Stage 2 is optimal within its actionable window in *Green Energy Exports* (2031-32) and *Progressive Change* (2036-37), and after its actionable window in *Step Change* (2047-48). The later optimal timing for Project Marinus Stage 2 in *Step Change* is driven by cost increases for Stage 2, the development of offshore wind under the Victorian Offshore Wind Target, and the influence of load growth within Tasmania (that reduces the oversupply of Tasmanian renewable energy).

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, spurred by the Tasmanian Renewable Energy Target. 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 Project Marinus in *Step Change* via TOOT analysis

Table 27 and Figure 9 present the relative market benefits of delivering Project Marinus (both stages) at their optimal timings based on *Step Change*'s least-cost DP compared to a case without these projects. The augmentation delivers gross benefits over the outlook period amounting to $2.8 billion mainly from avoided generator and storage capital costs, fuel costs, and FOM costs. Overall, Project Marinus Stage 1 and Project Marinus Stage 2 contribute roughly $340 million of the $17.85 billion net market benefits in *Step Change*.

[24] 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 27 Relative market benefits of Project Marinus in *Step Change*

Class of market benefits	Relative market benefits (NPV, $ million)
Generator and storage capital deferral	2,087
FOM cost savings	72
Fuel cost savings	509
VOM cost savings	-6
USE+DSP reductions	105
Other network investment (REZ augmentations)	15
Gross market benefits	2,781
Network (actionable and future ISP projects)	-2,439
Total market benefits	342

Figure 9 Annual relative market benefits of Marinus Link in *Step Change*

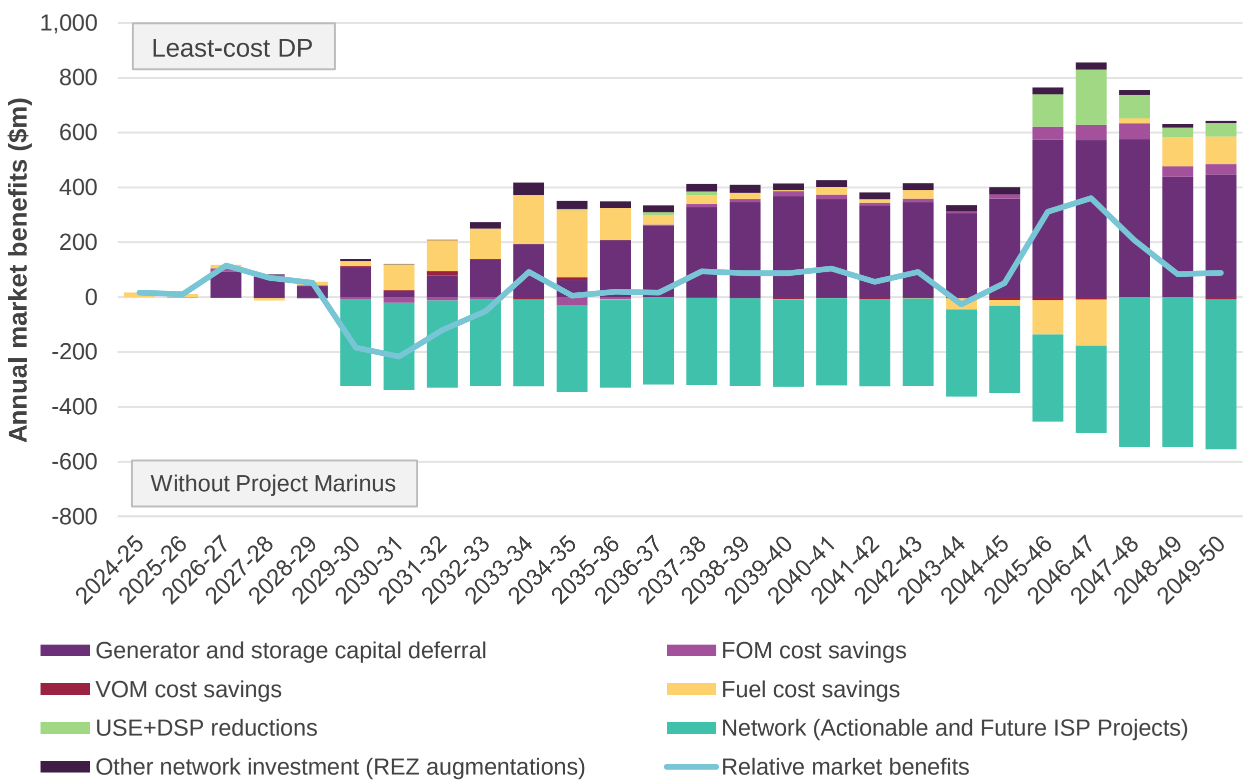


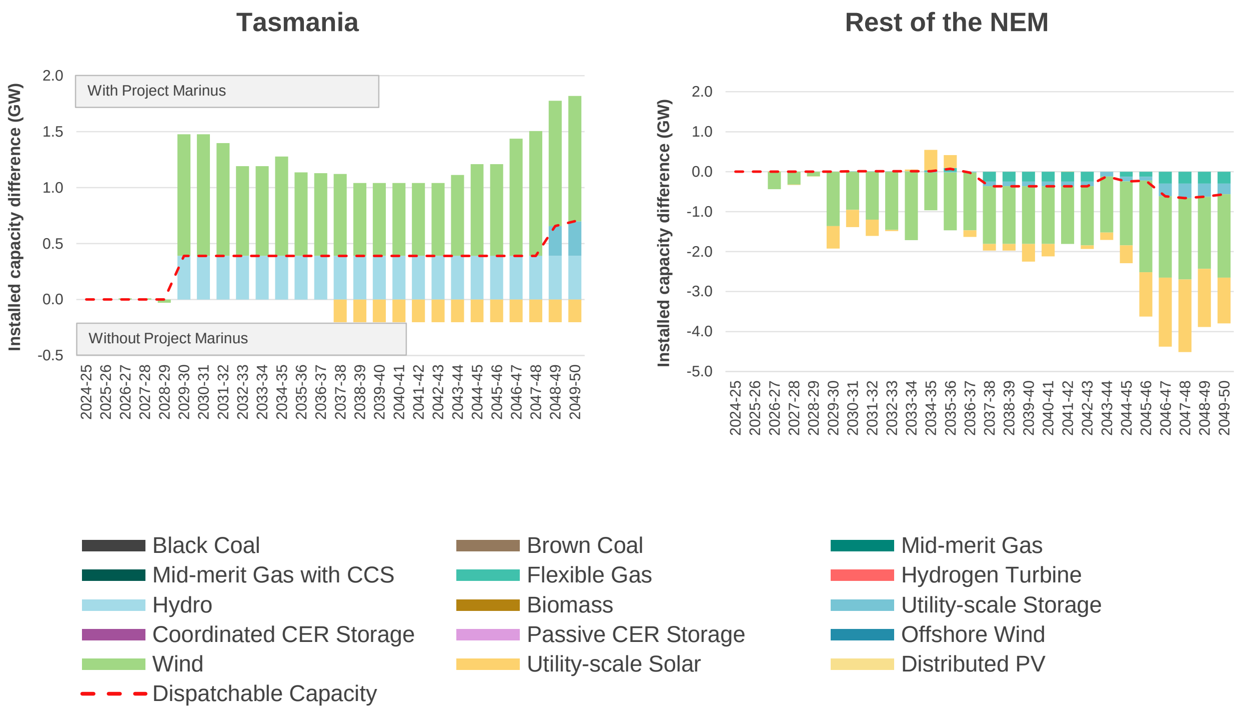
Figure 10 highlights the differences in generation capacity in Tasmania and the rest of the NEM with and without Project Marinus. From 2029-30, additional hydro capacity in Tasmania is unlocked with the development of Project Marinus Stage 1. As outlined in the 2023 IASR[25], Hydro Tasmania is assumed to re-purpose maintenance expenditure to physical works to increase capacities of some generators within the

[25] See the Flow Path Augmentation Options sheet in the 2023 IASR Assumptions Workbook for further details.

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 onshore wind in the North West Tasmania and Central Highlands REZs, as well as utility-scale storage in Tasmania in the late 2040s once Project Marinus Stage 2 is built.

Figure 10 Comparison of capacity with and without Project Marinus in *Step Change* (Stage 1 in 2030, Stage 2 in 2048)



Without the development of Project Marinus, additional capacity is required to meet demand in the rest of the NEM. This includes higher levels of onshore wind initially and then utility-scale solar from 2045-46 – mostly in Victoria and to a lesser extent New South Wales and Queensland, as Project Marinus would otherwise allow additional Tasmanian renewable generation to support the mainland regions. Around 500 MW of utility-scale deep storage capacity also replaces shallow storages in Victoria without Project Marinus.

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

The benefits of delivering Project Marinus (both stages) within its actionable window can be best observed by comparing CDP11 with CDP12, as seen in Table 28 below.

CDP11 has delivery of both stages of Project Marinus within the actionable windows, whereas CDP12 removes them as actionable projects. For *Green Energy Exports* and *Progressive Change*, which develop Project Marinus Stage 2 within its actionable window, delaying Project Marinus Stage 1 also requires delaying Stage 2, as the former is a pre-requisite for the latter.

Table 28 Comparing net market benefits between CDP11 and CDP12 ($ billion) – Project Marinus

	CDP11 – with actionable Project Marinus	CDP12 – without actionable Project Marinus	Change in net market benefits associated with not actioning the project[A]
Step Change	17.35	17.61	0.26
Progressive Change	7.24	6.24	-1.00
Green Energy Exports	46.35	42.64	-3.71
Weighted net market benefits	17.45	16.59	-0.86
Ranking based on weighted net market benefits	1	15	

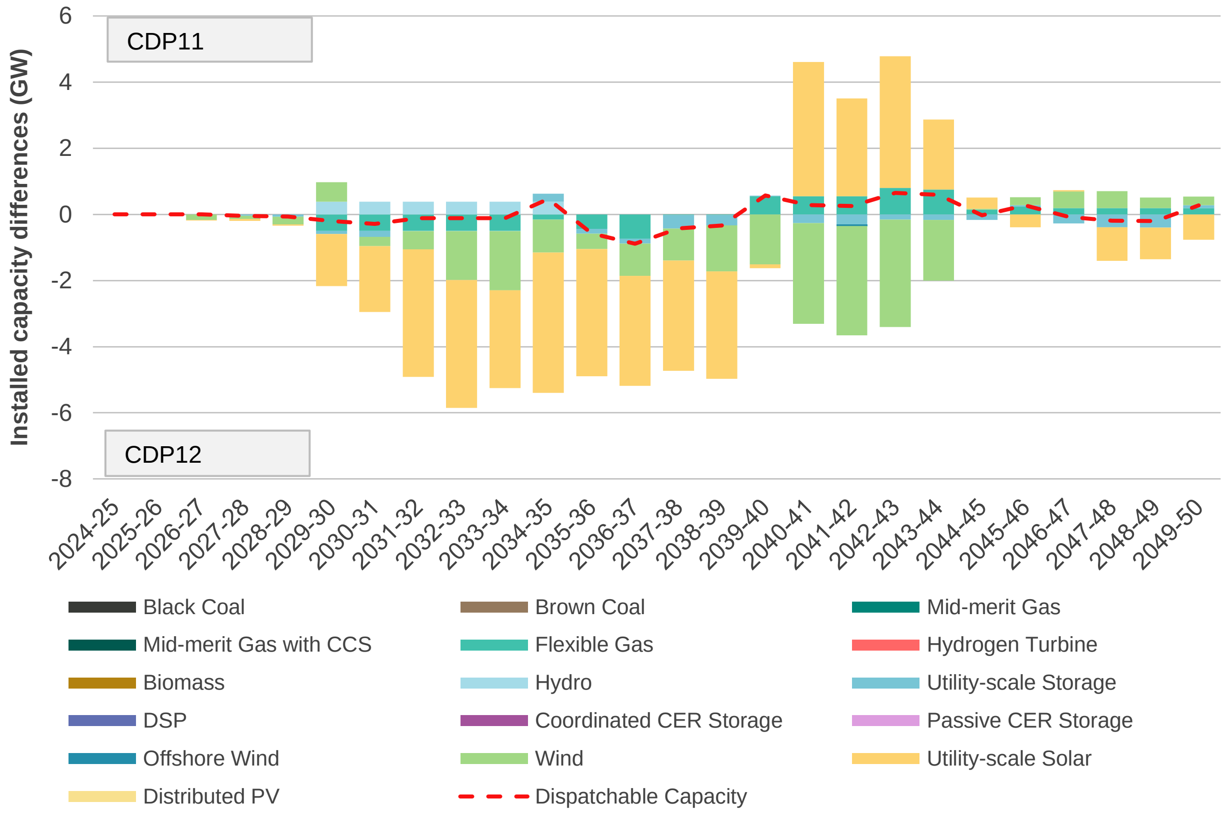
A. Figures in this column are based on the difference between the figures in the preceding two columns. Additionally, rounding differences may be present.

An actionable Project Marinus (both stages) delivers large relative market benefits in *Progressive Change* ($1 billion) and in *Green Energy Exports*, where it results in a $3.71 billion increase in net market benefits when delivered at an actionable timing.

In *Step Change*, delivering both stages at an actionable timing result in a decrease in net market benefits of $260 million, due to the late 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 $864 million.

As seen in Figure 11, in *Green Energy Exports* Project Marinus avoids nearly 3.9 GW of additional large-scale solar capacity by 2031-32 and around 1.8GW of additional wind capacity by 2033-34 needed to support electricity and hydrogen production demand.

Figure 11 Comparison of capacity with and without an actionable Project Marinus in *Green Energy Exports*



With an actionable Project Marinus, there is 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 2033-34, electricity consumption for export hydrogen and green steel production is around 15,500 GWh greater in Tasmania with the actionable augmentations. In their absence, export electrolyser capacity is instead developed across the mainland.

In *Progressive Change*, the benefits of an actionable Project Marinus stem from the deferral of 1 GW of wind in Victoria, avoided fuel costs, and reduction 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, limiting Tasmania's capacity to support the mainland during peak periods. An actionable Project Marinus Stage 2 also provides net market benefits mainly coming from deferred costs of additional GPG that would otherwise be developed on the mainland.

Finally, in *Step Change*, delaying Project Marinus (both stages) to outside of their actionable windows results in an increase in net market benefits of around $260 million. While delivering Stage 1 at an actionable timing does result in an increase in net market benefits, bringing forward Project Marinus Stage 2 does not avoid sufficient wind and solar capacity hence decreases the net market benefits of the actionable project.

Assessing the regrets associated with Project Marinus as an actionable project

Table 29 presents the weighted regrets in each of the scenarios and worst weighted regrets for CDP11 and CDP12. In CDP12, the regrets associated with a non-actionable Project Marinus are largest in *Green Energy*

Exports and drive the worst weighted regrets in CDP12. As mentioned, delaying this project results in an increase in builds across the NEM required to support growing demand.

Table 29 Weighted and worst weighted regrets of CDP11 and CDP12 ($ billion) – Project Marinus

	CDP11 – with actionable Project Marinus	CDP12 – without actionable Project Marinus	Change in weighted regrets associated with not actioning the project[A]
Step Change	0.22	0.10	-0.11
Progressive Change	0.17	0.59	0.42
Green Energy Exports	0.33	0.88	0.56
Worst weighted regrets	0.33	0.88	0.56
Ranking based on worst weighted regrets	3	15	

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 Transmission Link

The New England REZ Transmission Link augmentation[26] 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 kV line between central and northern New South Wales to access renewable generation from Northern New South Wales.

In this *Draft 2024 ISP*, the delivery of the first stage (New England REZ Transmission Link 1) is found to be optimal at EISD (2028-29) in *Green Energy Exports and Step Change* and in 2035-36 (beyond its actionable window) in *Progressive Change*. A second stage (New England REZ Transmission Link 2) is only actionable in *Green Energy Exports* (2028-29)[27]. In *Step Change and Progressive Change*, the second stage is only optimal beyond its actionable window.

The New England REZ Transmission Link provides a more cost-effective development of wind and solar builds in New South Wales to meet demand and achieve to state and federal renewable energy targets. 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.

New England REZ Transmission Link 1 is a 3 GW upgrade between Northern New South Wales and Central New South Wales which costs approximately $1,955 million in 2028-29 in *Green Energy Exports* and *Step Change*[28]. New England REZ Transmission Link 2 is a further upgrade of this flow path by another 3 GW (both

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

[27] This project was modelled earlier than its EISD (2032-33) in *Green Energy Exports*. While it is not expected to materially impact the conclusions of this analysis, this will be rectified in the final 2024 ISP.

[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.

directions) which costs around $1,594 in 2028-29[29] in *Green Energy Exports*[30]*.* It requires New England REZ Transmission Link 1 as a pre-requisite.

The New England REZ Transmission Link 1 also provides 2 GW augmentation of transmission connecting the New England REZ, while New England REZ Transmission Link 2 augments transmission in the New England REZ by a further 3 GW.

The New England REZ Extension is a further 1 GW upgrade of the New England REZ transmission network at a cost of $405 million in 2030-31 in both *Green Energy Exports* and *Step Change*. This subsequent upgrade, which requires the development of New England REZ Transmission Link 1 as a pre-requisite, is identified to be optimal at 2030-31 in both *Green Energy Exports* and *Step Change*, and at 2048-49 in *Progressive Change*.

Assessing the relative market benefits of New England REZ Transmission Link in *Step Change* via TOOT analysis

Table 30 and Figure 12 present the benefits that the New England REZ Transmission Link 1, New England REZ Transmission Link 2, and the New England REZ Extension provide in *Step Change*[31]*.* Overall, these augmentations contribute roughly $4 billion of the $17.85 billion net market benefits in *Step Change*, most of which comes from generator and storage capital deferrals as well as fuel cost savings.

Table 30 Relative market benefits of New England REZ Transmission Link in *Step Change*

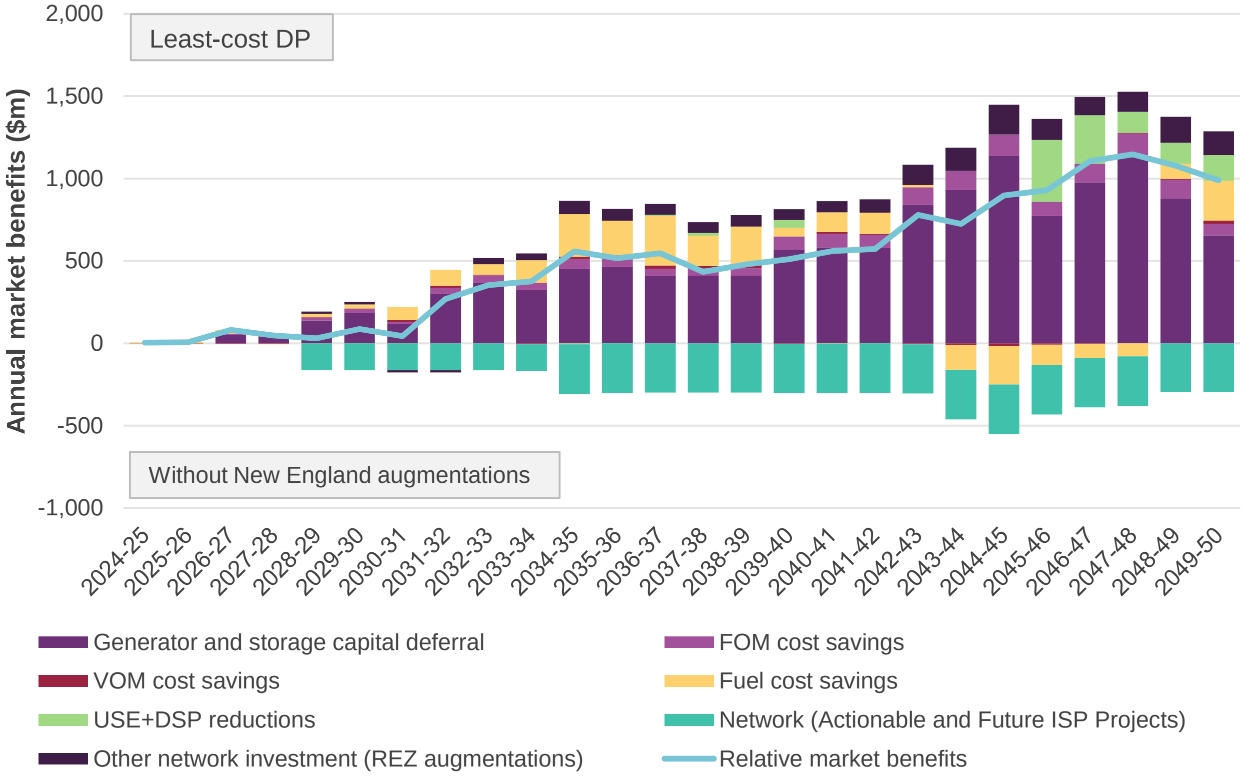
Class of market benefits	Relative market benefits (NPV, $ million)
Generator and storage capital deferral savings	3,954
FOM cost savings	498
Fuel cost savings	749
VOM cost savings	46
USE+DSP costs reduction	249
Other network investment (REZ augmentations)	785
Gross market benefits	6,281
Network (actionable and future ISP projects)	-2,260
Total market benefits	4,021

[29] In *Step Change*, the project is required in 2034-35 at a cost of $1,623 million once escalated via the transmission cost escalation methods described in the 2023 *Transmission Expansion Options Report*.

[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.

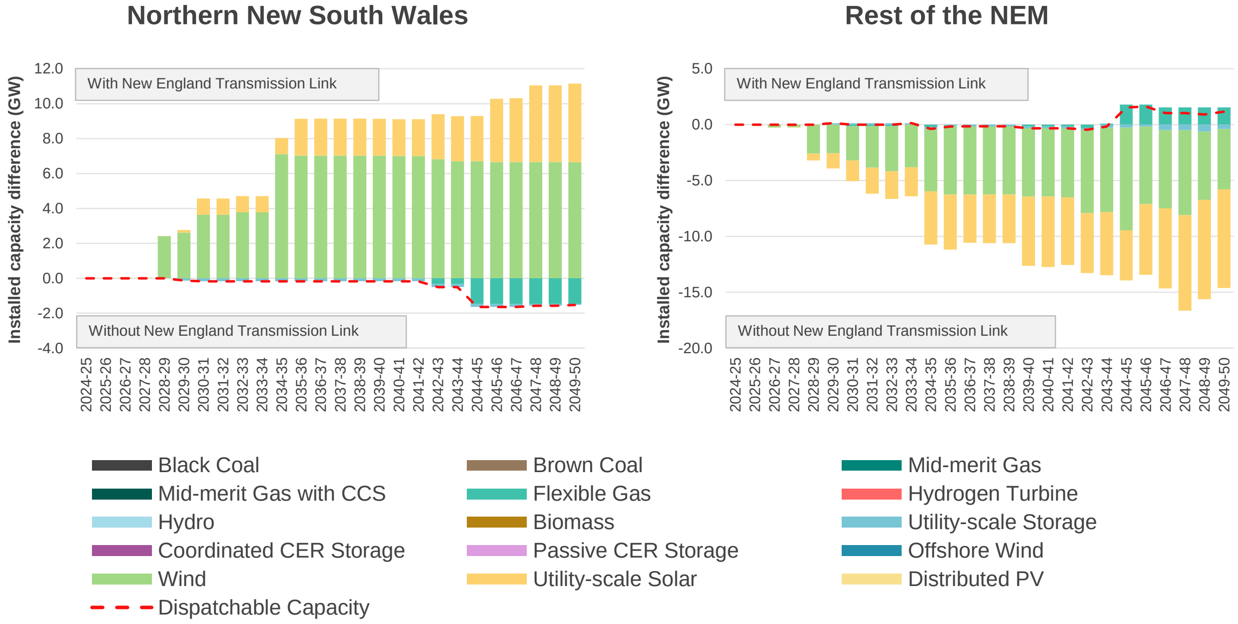
[31] Due to the pre-requisite delivery requirements, TOOT analysis of the New England REZ Transmission Link 1 also requires removal of the New England REZ Transmission Link 2 and New England REZ Extension.

Figure 12 Annual relative market benefits of New England REZ Transmission Link in *Step Change*



With the New England REZ Transmission Link, additional wind and solar capacity (7 GW and 2 GW, respectively) are developed in New England REZ. This additional generation development is to take advantage of the additional connectivity provided by the project.

Figure 13 Comparison of capacity with and without New England REZ Transmission Link in *Step Change* (Link 1 in 2028-29, Link 2 in 2034-35)



Without the New England REZ Transmission 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[32] are best demonstrated via a comparison of CDP11 with CDP2 (which is similar to CDP11 but without these two projects as actionable projects), see Table 31.

[32] 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 31 Comparing net market benefits between CDP11 and CDP2 ($ billion) – New England REZ Transmission Link 1 and New England REZ Extension

	CDP11 – with actionable New England REZ Transmission Link 1 and New England REZ Extension	CDP2 – 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	17.35	16.59	-0.76
Progressive Change	7.24	7.64	0.40
Green Energy Exports	46.35	44.57	-1.79
Weighted net market benefits	17.45	17.03	-0.43
Ranking based on weighted net market benefits	1	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 both *Step Change and Green Energy Exports*, delaying New England REZ Transmission Link 1 and New England REZ Extension beyond their actionable windows (to 2032-33) sees a reduction in net market benefits ($761 million and $1.79 billion respectively). A delay in the timing 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 Transmission Link 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 2027-28) 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 allowed to come in in 2032-33, it reduces curtailment of generation and sees further generation build in the New England REZ. Delaying these augmentations leads to increased expenditure and more concentrated development in Central West Orana over the outlook period.

In *Progressive Change* (which does not seek to develop the augmentation until after its actionable window), development of the New England REZ Transmission Link 1 and New England REZ Extension within the actionable window results in an overall reduction in net market benefits of $399 million compared to development at each project's optimal timing of 2035-36 and 2048-49 in this scenario.

No further generation builds in the REZ that would warrant uplift of the New England REZ network are needed until 2034-35, as there is a relatively lower level of demand in this scenario over the 2030s.

On a weighted net market benefits basis, these augmentations result in an increase of $428 million.

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

As Table 32 shows, the worst weighted regrets in both CDPs come from *Green Energy Exports*, highlighting the higher risks of under-investing in this scenario compared to the relatively lower risks of over-investment in *Progressive Change*.

Removing New England REZ Transmission Link 1 and New England REZ Extension as actionable projects (from CDP11 to CDP2) increases regrets from under-investing in *Green Energy Exports* and *Step Change.* In weighted regrets, they translate to a reduction by $268 million and $327 million, respectively. On the other hand, in *Progressive Change*, developing the New England REZ Transmission Link 1 and New England REZ Extension in their actionable windows results in higher weighted regrets from over-investment, but by only $168 million.

Overall, delivering these two projects within their actionable windows reduces the worst weighted regrets by $268 million.

Table 32 Weighted and worst weighted regrets of CDP11 and CDP2 ($ billion) – New England REZ Transmission Link 1 and New England REZ Extension

	CDP11 – with actionable New England REZ Transmission Link 1 and New England REZ Extension	CDP2 – 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	0.22	0.54	0.33
Progressive Change	0.17	0.00	-0.17
Green Energy Exports	0.33	0.60	0.27
Worst weighted regrets	0.33	0.60	0.27
Ranking based on worst weighted regrets	3	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 net market benefits of the New England REZ Extension as 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 CDP8. This upgrade comes in an optimal timing of 2030-31 in the least-cost DPs for *Step Change* and *Green Energy Exports,* but only in 2048-49 in *Progressive Change*.

As Table 33 shows, CDP8 (which defers the New England REZ Extension until after its actionable window) is one of the highest-ranking CDPs in weighted net market benefits, although tenth in worst weighted regrets. The weighted relative market benefits are minimal ($3 million), yet positive without the New England REZ Extension. In *Progressive Change*, an actionable timing reduces net market benefits by $187 million, but there are greater net market benefits in *Step Change* and *Green Energy Exports* ($77 million and $305 million, respectively). The net positive market benefits are driven by the improvement in net market benefits it provides in *Green Energy Exports*.

Table 33 Comparing net market benefits between CDP3 and CDP8 ($ billion) – New England REZ Extension

	CDP3 – with actionable New England REZ Extension	CDP8 – without actionable New England REZ Extension	Change in net market benefits associated with not actioning the project[A]
Step Change	17.85	17.78	-0.08
Progressive Change	7.25	7.44	0.19
Green Energy Exports	44.41	44.10	-0.30
Weighted net market benefits	17.38	17.38	0.00
Ranking based on weighted net market benefits	3	4	

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 34 below presents the weighted regrets and worst weighted regrets of both CDP3 and CDP8. Delaying the delivery of the project beyond its actionable window increases regrets in *Step Change* and *Green Energy Exports*, even if only marginally. Both CDPs ranked in the middle of the CDP collection in terms of worst weighted regrets, but CDP8 is approximately $46 million worse than CDP3.

Table 34 Weighted and worst weighted regrets of CDP3 and CDP8 ($ billion) – New England REZ Extension

	CDP3 – with actionable New England REZ Extension	CDP8 – without actionable New England REZ Extension	Change in weighted regrets associated with not actioning the project[A]
Step Change	0.00	0.03	0.03
Progressive Change	0.16	0.08	-0.08
Green Energy Exports	0.62	0.66	0.05
Worst weighted regrets	0.62	0.66	0.05
Ranking based on worst weighted regrets	8	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 (Reinforcing Sydney, Newcastle, and Wollongong Supply)

This augmentation was classified as an Actionable NSW Project in the 2022 ISP, hence its actionable window is four years from its EISD. Sydney Ring 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 2027-28 with a cost of $992 million[33].

The optimal timing across scenarios is always within its actionable window – its delivery is optimal at its EISD (2027-28) in *Green Energy Exports* and in 2028-29 in both *Step Change and Progressive Change.*

As New South Wales coal plants retire, the Sydney Ring augmentation provides for the ability to continue to supply loads in the Sydney, Newcastle, and Wollongong subregion by increasing the transfer capability to

[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.

import generation into the subregion. Without the augmentation, firming capacity would be required to be developed within the load centre in all scenarios (in particular GPG). 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 Sydney Ring in *Step Change* via TOOT analysis

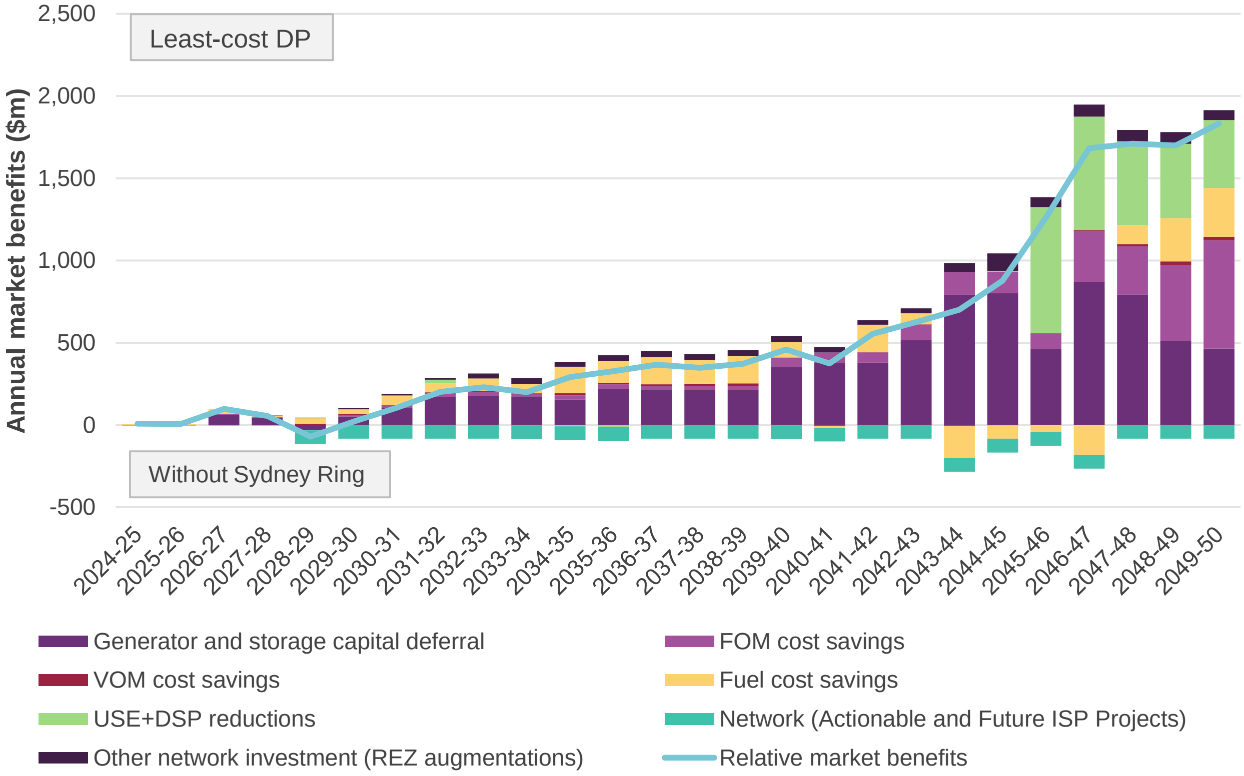
As Table 35 and Figure 14 show, Sydney Ring delivers benefits over the outlook period in *Step Change*. The majority of these benefits comes from generator and storage capital deferral, savings in FOM costs, as well as fuel cost savings. Relatively savings in avoided cost of using DSP in the Sydney, Newcastle, and Wollongong subregion also appears from 2045-46 onwards.

Overall, Sydney Ring contributes roughly $4.2 billion of the $17.85 billion net market benefits in *Step Change*.

Table 35 Relative market benefits of Sydney Ring in *Step Change*

Class of market benefits	Relative market benefits (NPV, $ million)
Generator and storage capital deferral savings	2,454
FOM cost savings	869
Fuel cost savings	613
VOM cost savings	46
USE+DSP costs reduction	634
Other network investment (REZ augmentations)	270
Gross market benefits	4,886
Network (Actionable and Future ISP Projects)	-679
Total market benefits	4,207

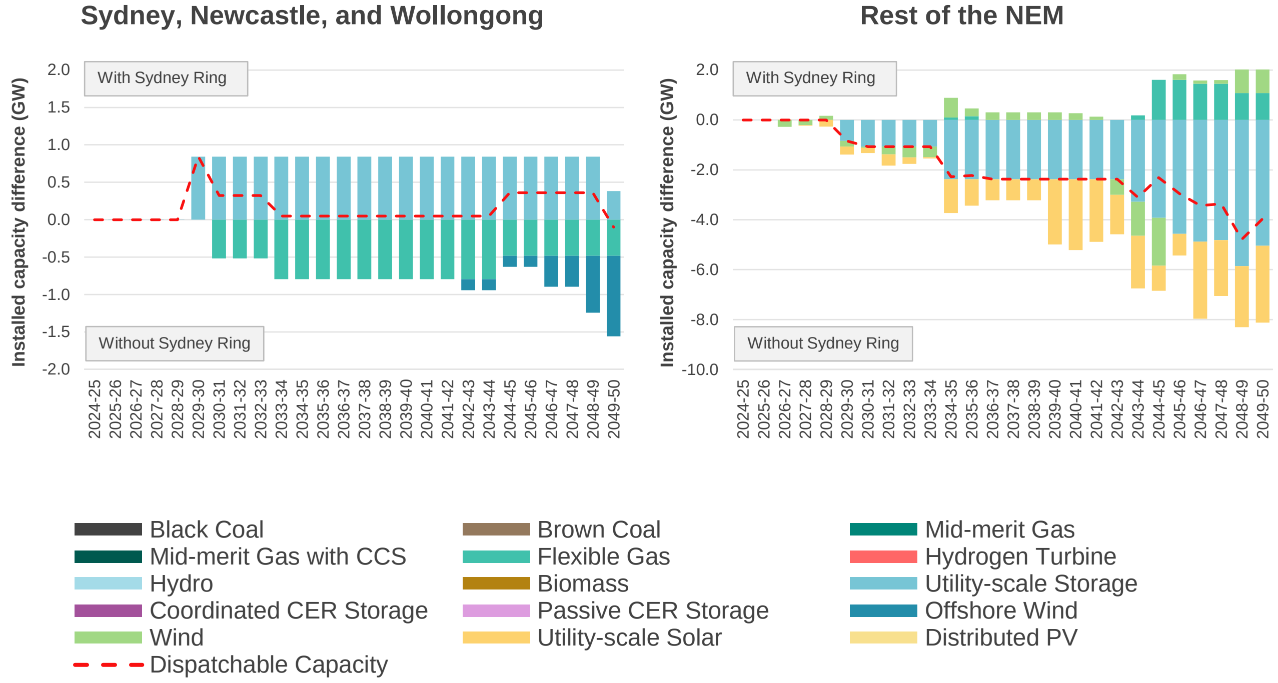
Figure 14 Annual relative market benefits of Sydney Ring in *Step Change*



As Figure 15 shows, over 800 MW of utility-scale storages are built in 2029-30 in the Sydney, Newcastle, and Wollongong subregion with Sydney Ring developed. Without Sydney Ring, this storage is replaced with 800 MW of GPG by 2033-34 to support the load centre's reliability. Furthermore, development of offshore wind would be needed in the 2040's (reaching 1 GW by 2049-50) to support the supply of energy into the sub-region).

In the rest of the NEM, by 2034-35 and without Sydney Ring, 2.2 GW of utility-scale storage in Central New South Wales and 230 MW of deep storage is replaced by 330 MW of medium storage. in Northern New South Wales are required to better utilise the increasingly congested existing transmission corridor. Around 2.3 GW of solar capacity is also developed in Queensland by 2039-40.

Figure 15 Comparison of capacity with and without Sydney Ring in *Step Change* (at an optimal timing of 2029-30)



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

The benefits and regrets associated with delaying the Sydney Ring augmentation beyond its actionable window across all the scenarios are best demonstrated by comparing CDP3 with CDP4 (which is equivalent to CDP3 but with Sydney Ring delayed to after its actionable window).

Table 36 Comparing net market benefits between CDP3 and CDP4 ($ billion) – Sydney Ring

	CDP3 – with actionable Sydney Ring	CDP4 – without actionable Sydney Ring	Change in net market benefits associated with not actioning the project[A]
Step Change	17.85	17.41	-0.44
Progressive Change	7.25	6.86	-0.39
Green Energy Exports	44.41	43.84	-0.57
Weighted net market benefits	17.38	16.94	-0.44
Ranking weighted net market benefits	3	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 all scenarios, an actionable Sydney Ring avoids GPG builds and utilisation in the Sydney, Newcastle, and Wollongong subregion. The deferral of generator capital costs associated with this, and to a lesser extent avoided fuel costs, are the main drivers of the net market benefits in *Step Change*.

In *Green Energy Exports*, the benefits of an actionable Sydney Ring are similarly derived from savings in generator and storage capital expenditure. If Sydney Ring is not delivered within an actionable timeframe, 600 MW of GPG is required in the Sydney, Newcastle, and Wollongong subregion from 2030-31 onwards, while there is also a need for an additional 1.5 GW of utility-scale storage in Central New South Wales by

2028-29 to manage flows into the Sydney, Newcastle, and Wollongong subregion. There is also a net addition of 1.3 GW of solar capacity across Central and South New South Wales in 2031-32.

Assessing the regrets associated with Sydney Ring as an actionable project

Table 37 below presents the weighted regrets across CDPs, and the change in weighted regrets associated with an actionable Sydney Ring. *Green Energy Exports* sees the greatest regrets associated with under-investment in either CDP 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 37 Weighted and worst weighted regrets of CDP3 and CDP4 ($ billion) – Sydney Ring

	CDP3 – with actionable Sydney Ring	CDP4 – without actionable Sydney Ring	Change in weighted regrets associated with not actioning the project[A]
Step Change	0.00	0.19	0.19
Progressive Change	0.16	0.33	0.17
Green Energy Exports	0.62	0.70	0.09
Worst weighted regrets	0.62	0.70	0.09
Ranking based on worst weighted regrets	8	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 SuperGrid South

The augmentation on the southern leg of the Queensland SuperGrid is found to be optimal if delivered at its EISD (2030-31) in all scenarios. As the project has not been identified in previous ISPs, the actionable window is only two years, as it is reasonably assumed that little momentum through regulatory processes has been accumulated to date. Benefits from this augmentation (Queensland SuperGrid South Option 5) stem from being able to improve access to the Borumba Dam Pumped Hydro as well as allowing greater energy and capacity sharing between southern and central Queensland.

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

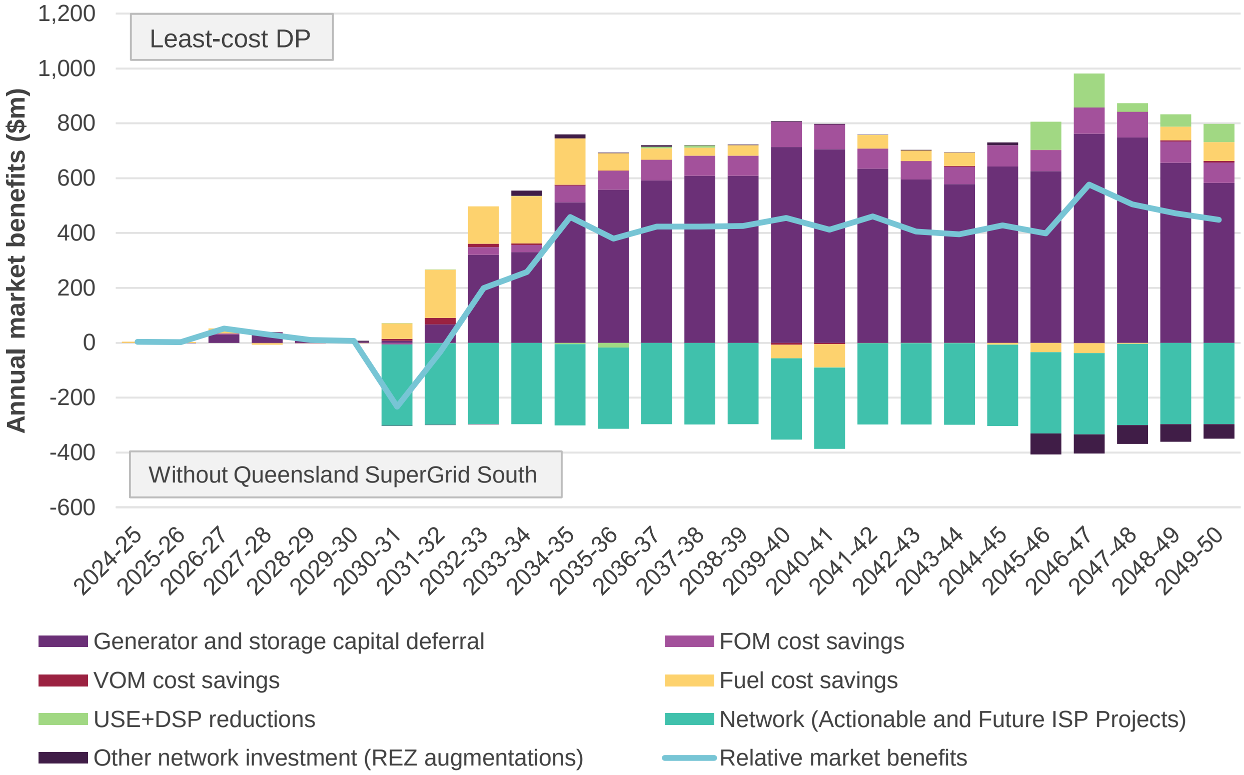
The benefits provided by Queensland SuperGrid South in *Step Change* are presented in Table 38 and Figure 16. Benefits are primarily due to deferred capital costs, as there is a need for additional utility-scale storage, from the mid-2030s without the augmentation (primarily in Queensland). Queensland SuperGrid South contributes approximately $2 billion of the $17.85 billion in net market benefits in *Step Change*.

Table 38 Relative market benefits of Queensland SuperGrid South in *Step Change*

Class of market benefits	Relative market benefits (NPV, $ million)
Generator and storage capital deferral	3,401
FOM cost savings	400
Fuel cost savings	435

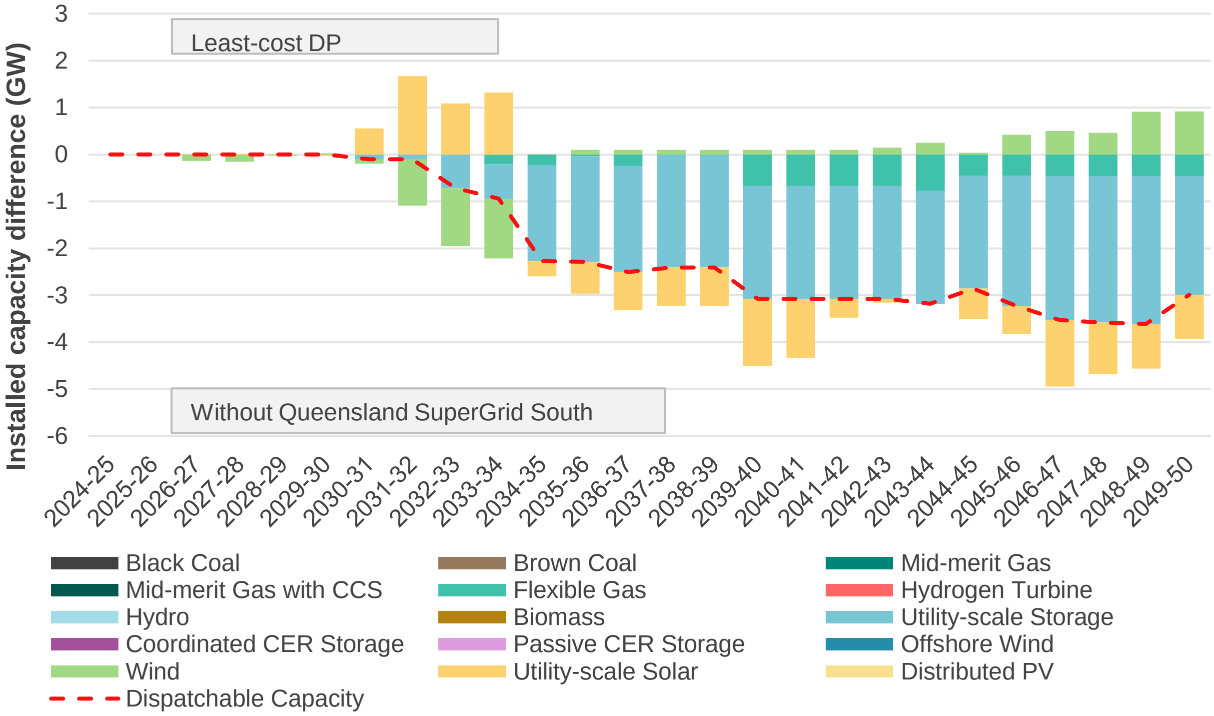
Class of market benefits	Relative market benefits (NPV, $ million)
VOM cost savings	26
USE+DSP reductions	72
Other network investment (REZ augmentations)	20
Gross market benefits	4,354
Network (Actionable and Future ISP Projects)	-2,116
Total market benefits	2,238

Figure 16 Annual relative market benefits of Queensland SuperGrid South in *Step Change*



Developing Queensland SuperGrid South in *Step Change* would prevent the need to build around 2 GW of utility scale storage in Queensland by 2035, avoid additional capacity requirement in southern regions in later years, and allow for more effective utilisation of central Queensland capacity in later years to support demand growth, see Figure 17.

Figure 17 Comparison of generation capacity with and without Queensland SuperGrid South in *Step Change*



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

As Table 39 shows, the benefits of actioning Queensland SuperGrid South can be derived by comparing CDP3 (the least-cost DP for *Step Change*) and CDP15, which delays the project until after its actionable window (a delay of only two years).

An actionable augmentation delivers net market benefits in *Step Change* ($160 million) and *Green Energy Exports* ($200 million) but increases the total system cost in *Progressive Change* by $175 million. On a weighted net market benefits basis, the project delivers positive benefits by around $25 million. Delaying the project by the minimum time appropriate for extending beyond its actionable window is ranked sixth best in weighted net market benefits amongst the CDP collection.

Table 39 Comparing net market benefits between CDP3 and CDP15 ($ billion) – Queensland SuperGrid South

	CDP3 – with actionable Queensland SuperGrid South	CDP15 – without actionable Queensland SuperGrid South	Change in net market benefits associated with not actioning the project[A]
Step Change	17.85	17.69	-0.16
Progressive Change	7.25	7.43	0.18
Green Energy Exports	44.41	44.21	-0.20
Weighted net market benefits	17.38	17.36	-0.02
Ranking weighted net market benefits	3	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.

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 solar and wind builds in Central and North Queensland. These benefit drivers are similar in *Progressive Change*, as well as avoiding the need for alternative dispatchable capacity (around 500 MW of additional GPG) in southern Queensland.

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

Table 40 below presents the weighted regrets across the scenarios for CDP3 and CDP15. It shows that delivering the project shortly after its actionable window increases regrets in both *Step Change* and *Green Energy Exports*, with CDP15 ranked marginally worse in worst weighted regrets than CDP3. The scale of regrets is relatively small except in *Green Energy Export*, which includes earlier coal closures and therefore has increased need for the improved access to the Borumba Dam Pumped Hydro, as well as the improved sharing of intra-regional resources when available.

Table 40 Weighted and worst weighted regrets of CDP3 and CDP15 ($ billion) – Queensland SuperGrid South

	CDP3 – with actionable Queensland SuperGrid South	CDP15 – without actionable Queensland SuperGrid South	Change in net market benefits associated with not actioning the project[A]
Step Change	0.00	0.07	0.07
Progressive Change	0.16	0.09	-0.07
Green Energy Exports	0.62	0.65	0.03
Worst weighted regrets	0.62	0.65	0.03
Ranking based on worst weighted regrets	8	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.

Gladstone Grid Reinforcement

Similar to Queensland SuperGrid South, this augmentation is optimal if delivered within its actionable window in all scenarios. Its benefits arise as a result of supplying the Gladstone subregion as coal generation retires. 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.

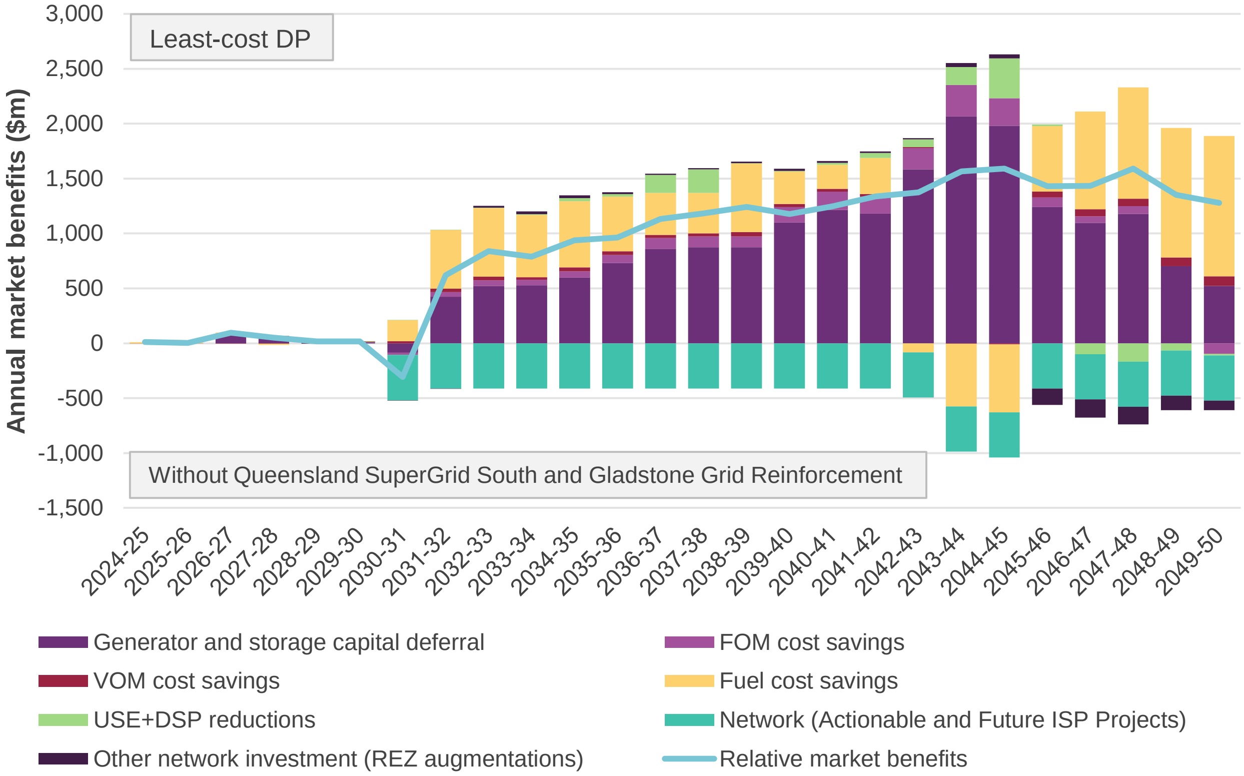
Assessing the relative market benefits of Gladstone Grid Reinforcement and Queensland SuperGrid South in *Step Change* via TOOT analysis

The benefits associated with these augmentations are presented in Table 41 and Figure 18 for *Step Chan*ge. These augmentations deliver net market benefits coming from avoided generator and storage capital, and fuel cost savings in Gladstone Grid. The augmentations contribute approximately $7 billion of the $17.85 billion in net market benefits in *Step Change*.

Table 41 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	5,749
FOM cost savings	541
Fuel cost savings	3,229
VOM cost savings	231
USE+DSP reductions	255
Other network investment (REZ augmentations)	7
Gross market benefits	10,012
Network (Actionable and Future ISP Projects)	-2,912
Total market benefits	7,100

Figure 18 Annual relative market benefits of Queensland SuperGrid South and Gladstone Grid Reinforcement in *Step Change*



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

Table 42 presents the change in net market benefits of CDP3 and CDP16 (which is similar list 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 $282 million and $1 billion), while increasing the system cost in *Progressive Change* by $301 million. Overall, delaying both projects result in a reduction in weighted net market benefits of around $147 million.

While not presented below, a comparison of CDP15 and CDP16 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 $122 million.

Overall, CDP16 is ranked relatively lowly in the CDP collection – ninth best in weighted net market benefits.

Table 42 Comparing net market benefits between CDP3 and CDP16 ($ billion) – Queensland SuperGrid South and Gladstone Grid Reinforcement

	CDP3 – with actionable Queensland SuperGrid South and Gladstone Grid Reinforcement	CDP16 – without actionable Queensland SuperGrid South and Gladstone Grid Reinforcement	Change in net market benefits associated with not actioning the project[A]
Step Change	17.85	17.57	-0.28
Progressive Change	7.25	7.55	0.30
Green Energy Exports	44.41	43.39	-1.01
Weighted net market benefits	17.38	17.24	-0.15
Ranking weighted net market benefits	3	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.

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 GPG in the Gladstone subregion to support the load growth that is forecast in that scenario. Without these augmentations within their actionable windows, nearly1.1 GW of additional utility-scale storage is required in Queensland by 2030-31. This capacity is not required for another almost twenty years if both augmentations are delivered in their actionable windows. The Gladstone Grid Reinforcement avoids around 375 MW of additional GPG by 2030-31 in the Gladstone Grid subregion, which is never required if the augmentation is delivered in that year instead.

In *Progressive Change*, as in the case of Queensland SuperGrid South, 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, as well as deferral of 500 MW of GPG development in South Queensland.

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

Table 43 below presents the weighted regrets across the scenarios for CDP3 and CDP16.

The worst weighted regrets for CDP16 are driven by the risks associated with under-investment in *Green Energy Exports* relative to what the least-cost DP for that scenario develops. Regrets range from $37 million in *Progressive Change* to $771 million in *Green Energy Exports*. Overall, CDP16 is ranked thirteenth best for worst weighted regrets.

Table 43 Weighted and worst weighted regrets of CDP3 and CDP16 ($ billion) – Queensland SuperGrid South and Gladstone Grid Reinforcement

	CDP3 – with actionable Queensland SuperGrid South and Gladstone Grid Reinforcement	CDP16 – without actionable Queensland SuperGrid South and Gladstone Grid Reinforcement	Change in weighted regrets associated with actioning the project[A]
Step Change	0.00	0.12	0.12
Progressive Change	0.16	0.04	-0.13
Green Energy Exports	0.62	0.77	0.15
Worst weighted regrets	0.62	0.77	0.15
Ranking based on worst weighted regrets	8	13	

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

A6.5.3 Summarising the benefits of a coordinated approach to transmission development

Table 44 presents a comparison of the weighted net market benefits of CDP3, which is the least-cost DP under the most-likely *Step Change* scenario, compared with CDP17, which has no projects that are developed within their actionable windows, in all scenarios.

Table 44 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*	17.85	7.25	44.41	17.38
CDP17: No actionable projects	15.14	5.90	34.74	14.20
Net market benefits due to actionability of projects	2.71	1.35	9.67	3.18

The weighted net market benefits delivered by the transmission projects within their actionable windows amounts to $3.18 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 and therefore time if they were deferred to later delivery timings. This leads to a longer gap between an actionable timing and the timeframe they would be able to be deliverable if deferred, leading to greater potential impact on the NEM's development, and therefore the costs that differ with these alternate timings.
- Applying a rising cost for transmission projects (in real dollars) over the outlook period increases the relative cost for delayed delivery of these projects, compared to the cost of delay previously when cost escalation was not included (as per the 2022 ISP).
- Greater change is forecast in the medium term to deliver various renewable energy and emissions reduction targets, and stronger growth in consumer demand. This leads to a difference in development outcomes with less transmission availability to efficiently connect low emissions energy developments.
- More potential actionable projects in this Draft 2024 ISP (as outlined in previous sections) compared to the 2022 ISP, leading to a greater impact of project delays.

A6.6 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 45 presents the top five CDPs from the scenario collection using the risk-neutral weighted net market benefits method, and the risk-averse least worst-weighted regrets method. The differences in transmission augmentations across these CDPs is provided in Table 46.

Table 45 Top five 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
11	17.35	7.24	46.35	17.45	1	0.33	3
14	17.25	7.06	46.93	17.42	2	0.26	1
3	17.85	7.25	44.41	17.38	3	0.62	8
8	17.78	7.44	44.10	17.38	4	0.66	10
7	17.79	7.07	44.97	17.36	5	0.53	4

Table 46 Potential actionable projects in the top five CDPs

In these CDPs …		…These projects would be actionable:										
		Gladstone Grid Reinforcement	Queensland SuperGrid South	QNI Connect	New England REZ Transmission Link	New England REZ Extension	Sydney Ring	HumeLink	VNI West	Project Marinus Stage 1	Project Marinus Stage 2	TAS Central Highlands REZ Upgrade
3	*Step Change* least-cost	✓	✓		✓	✓	✓	✓	✓	✓		✓
8	CDP3 without actionable New England REZ Extension	✓	✓		✓		✓	✓	✓	✓		✓
7	CDP3 with actionable QNI Connect	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓
11	CDP3 with actionable Project Marinus Stage 2	✓	✓		✓	✓	✓	✓	✓	✓	✓	✓
14	CDP3 with actionable Project Marinus Stage 2 and actionable QNI Connect	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓

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 the sensitivity analysis. 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.

For this Draft 2024 ISP, CDP11 is the top CDP in terms of weighted net market benefits and ranks third in worst weighted regrets. This set of projects facilitates the efficient connection and sharing of VRE across the NEM to support retirement of coal and increasing demand over the outlook period in addition to the achievement of the various energy policies considered in this Draft 2024 ISP.

The regrets for CDP11 are mostly associated with the risks of under-investing under the *Green Energy Exports* scenario, where faster coal retirements and growing hydrogen demands result in greater benefits associated with earlier transmission development.

CDP11 is followed very closely by CDP14, which is otherwise the same collection of potentially actionable projects but with a delivery of QNI Connect within its actionable window. Development of QNI Connect within its actionable window effectively leads to a lower weighted net market benefits by $37 million compared with CDP11 as it is only needed to be delivered within its actionable window in one scenario. However, the point of difference between the CDPs – QNI Connect – is not as valuable an augmentation in the event that the Pioneer-Burdekin Pumped Hydro Project proceeds, which is anticipated by the Queensland Energy and Jobs Plan to be needed to achieve the full scale of coal closures and achieve the objectives of the Plan.

The least-cost DP for *Step Change*, CDP3, provides the third highest net market benefits. This CDP does not deliver Project Marinus Stage 2 within its actionable window, and its net market benefits in *Green Energy Exports* are much lower than in CDP11 or CDP14. As discussed above, delaying Project Marinus Stage 2 results in greater regrets from the risks of under-investment in *Green Energy Exports*.

CDP8 has similar weighted net market benefits as that of CDP3, but it does not feature a delivery of New England REZ Extension within its actionable window, which means it has lower capital cost but also lower benefits. Similar to most CDPs, its higher worst weighted regrets are from the risks of under-investment in the *Green Energy Exports* scenario.

CDP7, which is similar to CDP3 but with development of QNI Connect within its actionable window, is the fifth highest CDP from the perspective of weighted net market benefits. As discussed in Section A6.5.2 above, it is most beneficial in the event of earlier retirement of Queensland coal generators (earlier than is anticipated by the Queensland Energy and Jobs Plan) and prior to the development of both of Queensland's major deep-storage projects.

Overall, each of the CDPs presents a potential trade-off between weighted net market benefits and worst weighted regrets that appropriately consider the relative likelihood of each scenario. As considered in the 2022 ISP and allowed for in the AER's CBA Guidelines, it is important to consider the potential improved resilience that key CDPs may provide to alternative assumptions affecting the future conditions that the NEM will face. This Draft 2024 ISP explores this by examining the insights provided by the sensitivity analysis against the shortlist presented above, with greatest focus on CDP11, CDP14, CDP3, and CDP7. These are the highest-ranked CDPs in terms of weighted net market benefits and are also highly ranked in terms of worst weighted regrets (particularly CDP11, CDP14 and CDP7). Additional risk analysis is likely to influence the final 2024 ISP assessment.

Because it has the highest weighted net market benefits and low worst weighted regrets amongst these CDPs, AEMO considers CDP11 to be the most appropriate candidate to be the Optimal Development Path, subject to the assessment below. Section A6.7 discusses the robustness of the CBA collection, then Section A6.9 presents a final assessment of the candidates and the ODP.

Section A6.8 below further examines whether an alternative CDP would help to align with consumer risk preferences, and it also provides more insights on distributional effects.

A6.7 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 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.

Additional sensitivity analyses have been included in this Draft 2024 ISP than was outlined in the 2023 IASR. Some sensitivities modelled in the 2022 ISP, such as offshore wind sensitivity or a low gas price sensitivity, have not been applied this time as analysis has focused on other less-explored risks, such as constrained supply chains and reduced social licence. AEMO may conduct further sensitivity analyses for when producing the final 2024 ISP.

The impact of these sensitivities on generation and storage capacity development is explored in depth in Appendix 2.

A6.7.1 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 47 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* (CDP3). In this CDP, approximately 1.7 GW less renewable generation and firming capacity (split between wind, solar, and pumped hydro) is developed by 2034-35 compared to developments under the central discount rate assumption. As a result, more existing GPG is utilised. See Appendix 2 for more detail on generation insights.

Table 47 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
11	6.98	2.08	25.68	7.73	1	0.22	1
8	7.45	2.31	23.54	7.71	2	0.54	9
3	7.43	2.13	23.82	7.66	3	0.50	7
14	6.84	1.80	26.02	7.60	4	0.30	3
7	7.32	1.85	24.22	7.55	6	0.44	4

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

Table 48 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 CDP8) see an improvement in their ranking, while CDPs that accelerate investments (such as CDP14) are less favourable.

CDP11 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 48 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
11	CDP3 with actionable Project Marinus Stage 2	1	1	1	3
8	CDP3 without actionable New England REZ Extension	2	9	4	10
3	*Step Change* least-cost DP	3	7	3	8
14	CDP3 with actionable Project Marinus Stage 2 and QNI Connect	4	3	2	1
7	CDP3 with actionable QNI Connect	6	4	5	4

Note: As the sensitivity analysis were 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 (CDP11, CDP14 and CDP3), shown in Table 49, demonstrates that accelerated investments in certain projects become increasingly regretful with higher discount rates. In the table, while CDP11 remains the top-ranked CDP, the reduction in weighted net market benefits of CDP14 in comparison to CDP11 would more than triple under a high discount rate, from $37 million to $128 million.

Table 49 CDP11, CDP14 and CDP3, core assumptions and 10.5% discount rate ($ billion)

Discount rate	CDP	*Step Change*	*Progressive Change*	*Green Energy Exports*	WNMB	Reduction in WNMB relative to CDP11	WNMB ranking
Core assumptions	11	17.35	7.24	46.35	17.45	-	1
	14	17.25	7.06	46.93	17.42	-0.04	2
	3	17.85	7.25	44.41	17.38	-0.07	3
With 10.5% discount rate	11	6.98	2.08	25.68	7.73	-	1
	14	6.84	1.80	26.02	7.60	-0.13	4
	3	7.43	2.13	23.82	7.66	-0.07	3

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

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 50 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
14	42.74	18.71	95.27	40.53	1	0.25	1
11	42.77	18.71	94.50	40.42	2	0.36	3
7	43.12	18.64	93.33	40.37	4	0.54	4
3	43.13	18.64	92.54	40.25	5	0.66	8
8	42.95	18.78	92.27	40.20	7	0.70	9

Note: As the sensitivity analysis were 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 50 shows the performance of key CDPs under the low discount rate sensitivity and demonstrates the changes in the CDP rankings. CDP13 is not included in the shortlisted CDPs but is included in this table as it becomes the third-ranked CDP under this sensitivity.

Table 51 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
14	CDP3 with actionable Project Marinus Stage 2 and QNI Connect	1	1	2	1
11	CDP3 with actionable Project Marinus Stage 2	2	3	1	3
13	CDP3 with actionable Project Marinus Stage 2 and Mid North South Australia Upgrade	3	2	7	2

CDP	Description	3% discount rate		Core assumptions	
		WNMB rank	WWR rank	WNMB rank	WWR rank
7	CDP3 with actionable QNI Connect	4	4	5	4
3	*Step Change* least-cost DP	5	8	3	8
8	CDP3 without actionable New England REZ Extension	7	9	4	10

Note: As the sensitivity analysis were 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 CDP7, CDP11, CDP14 and CDP13) improve, and are now the top-ranked CDPs in terms of both weighted net market benefits and worst weighted regrets.

CDP11 is reasonably resilient to the reduction in discount rate, falling only behind CDP14 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 52 presents the change in net market benefits associated with CDP11, CDP14 and CDP3 under the core assumptions and with a 3% discount rate. The reduction in net market benefits associated with CDP3 relative to CDP11 (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 CDP11 now being preferred to CDP3 in *Progressive Change*. Finally, CDP14 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 52 CDP11, CDP14 and CDP3, 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	11	17.35	7.24	46.35	17.45	-	1
	14	17.25	7.06	46.93	17.42	-0.04	2
	3	17.85	7.25	44.41	17.38	-0.07	3
With 3% discount rate	11	42.77	18.71	94.50	40.42	-	2
	14	42.74	18.71	95.27	40.53	0.11	1
	3	43.13	18.64	92.54	40.25	-0.17	5

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

A6.7.2 *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 is 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 53 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 A6.6 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 53 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. As CDP1 is not in the previous shortlist of CDPs identified in Section A6.6, it is not addressed in detail in subsequent analysis in this section.

CDP14 (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 CDP11. 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 53 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**
1	Green Energy Exports least-cost DP	26.44	21.04	1	17.11	17.02	10
14	CDP3 with actionable Project Marinus Stage 2 and actionable QNI Connect	25.61	21.02	2	17.25	17.42	2
11	CDP3 with actionable Project Marinus Stage 2	25.48	20.95	3	17.35	17.45	1
7	CDP3 with actionable QNI Connect	25.66	20.75	5	17.79	17.36	5
3	*Step Change* least-cost DP	25.55	20.69	7	17.85	17.38	3
8	CDP3 without actionable New England REZ Extension	25.41	20.67	8	17.78	17.38	4

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

The regrets associated with CDP1 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. CDP11 remains third-best, but CDP14 and CDP13 are ranked first and second.

A6.7.3 *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 19, 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 19 Difference in NEM annual consumption between *Step Change* and *Reduced Energy Efficiency*

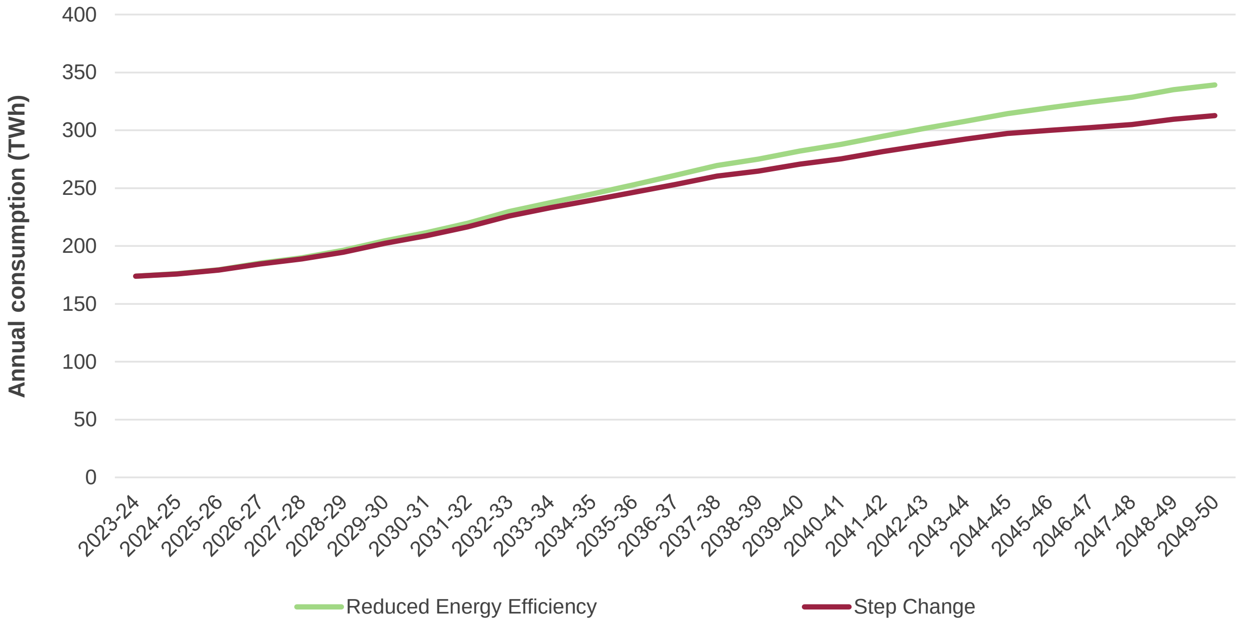


Table 54 highlights how the ranking of CDPs remains relatively resilient to this change, when based on weighted net market benefits. Furthermore, the quantum of net market benefits under this sensitivity does not change significantly, as the change in assumptions impacts only the second half of the outlook period for both the counterfactual DP and all CDPs.

Table 54 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
11	CDP3 with actionable Project Marinus Stage 2	17.46	17.50	1	17.35	17.45	1
14	CDP3 with actionable Project Marinus Stage 2 and QNI Connect	17.38	17.48	2	17.25	17.42	2
3	*Step Change* least-cost DP	17.90	17.40	3	17.85	17.38	3

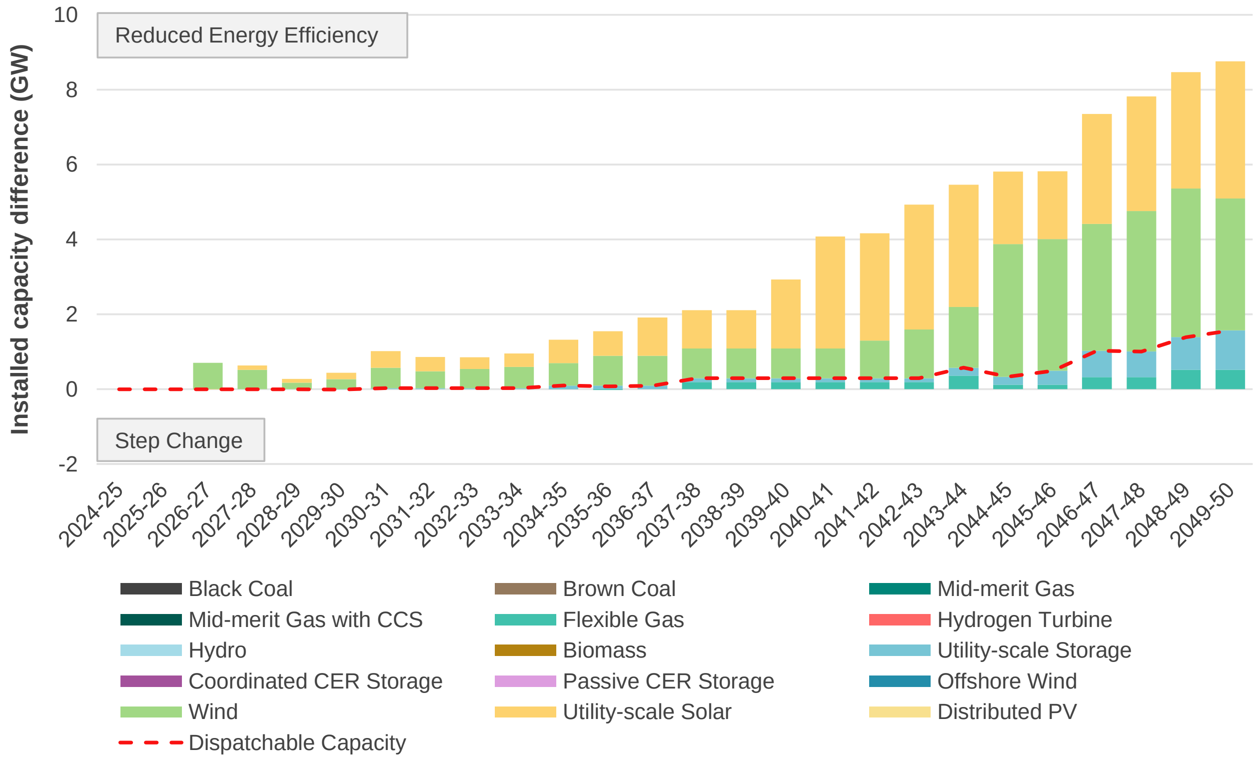
		Reduced energy efficiency sensitivity			With core *Step Change*		
8	CDP3 without actionable New England REZ Extension	17.80	17.39	4	17.78	17.38	4
7	CDP3 with actionable QNI Connect	17.84	17.38	5	17.79	17.36	5

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

As Figure 20 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. This means that if energy efficiency measures do not materialise as much as what is forecast in the *Step Change* scenario, 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.

More detail on the capacity outlooks for the sensitivities can be found in Appendix 2.

Figure 20 Difference in capacity between the least-cost DP for *Step Change* and for *Reduced Energy Efficiency* sensitivity

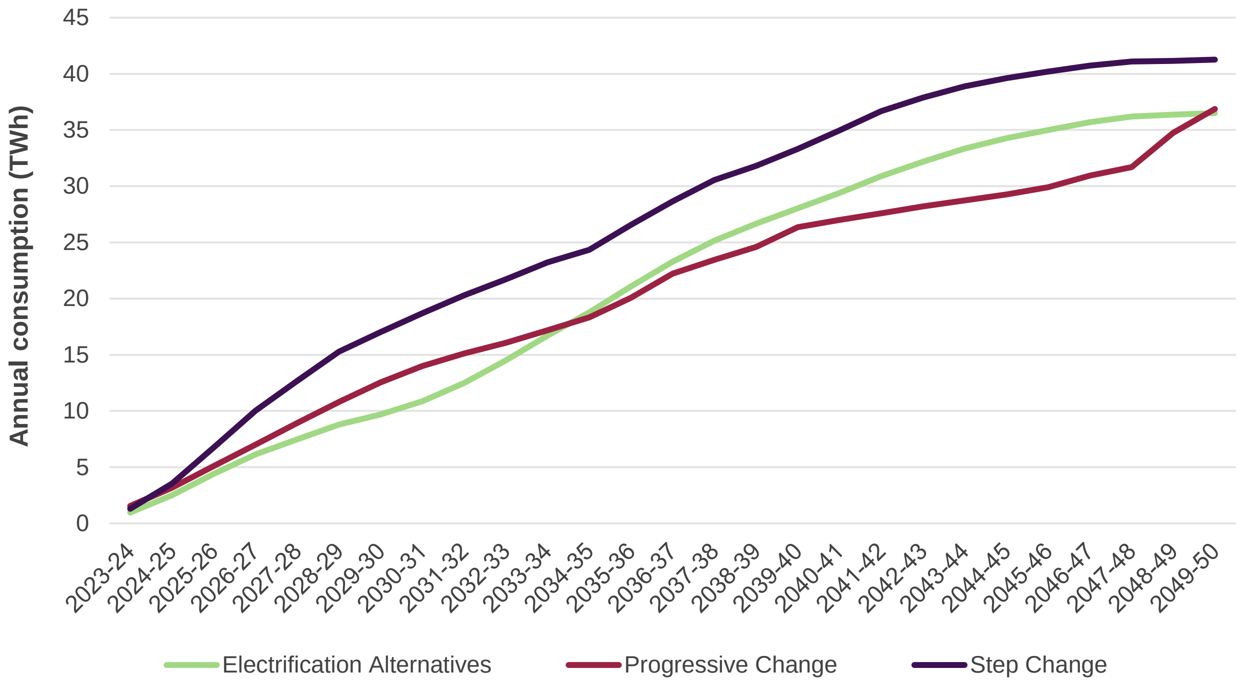


The worst weighted regrets rankings are relatively resilient to this sensitivity to *Step Change* given the limited impacts described above.

A6.7.4 *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 21 shows the difference between the electrification forecast for *Step Change, Progressive Change,* and the *Electrification Alternatives* sensitivity.

Figure 21 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 shown in Table 55. However, while the reductions are generally similar across the CDP collection, the biggest reduction amongst the top-ranked CDPs is for CDP7 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, CDP11 still has the highest weighted net market benefits.

Table 55 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**
11	CDP3 with actionable Project Marinus Stage 2	16.83	17.23	1	17.35	17.45	1
8	CDP3 without actionable New England REZ Extension	17.33	17.19	2	17.78	17.38	4
14	CDP3 with actionable Project Marinus Stage 2 and actionable QNI Connect	16.72	17.19	3	17.25	17.42	2
3	*Step Change* least-cost DP	17.33	17.16	4	17.85	17.38	3
7	CDP3 with actionable QNI Connect	17.23	17.12	5	17.79	17.36	5

Note: As the sensitivity analysis were 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.

A6.7.5 *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 56 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 CDP11 (which has an actionable Project Marinus Stage 2) and CDP3 increases from $72 million in core scenarios with *Step Change* to $110 million in Constrained Supply Chains sensitivity. CDP7 (with an actionable QNI Connect) becomes the top-ranked CDP in *Step Change* under this sensitivity, followed by CDP3. 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.

CDP11 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 56 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**
11	CDP3 with actionable Project Marinus Stage 2	22.04	19.47	1	17.35	17.45	1
14	CDP3 with actionable Project Marinus Stage 2 and QNI Connect	22.02	19.47	2	17.25	17.42	2
7	CDP3 with actionable QNI Connect	22.47	19.38	3	17.79	17.36	5
8	CDP3 without actionable New England REZ Extension	22.39	19.37	4	17.78	17.38	4
3	*Step Change* least-cost DP	22.45	19.36	5	17.85	17.38	3

Note: As the sensitivity analysis were 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*.

A6.7.6 *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 explores 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 57. 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 (CDP11 and CDP14) 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, CDP8 jumps to the top of the rankings as it naturally has lower VRE development, but CDP11 comes in a close second.

Table 57 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**
8	CDP3 without actionable New England REZ Extension	13.98	15.75	1	17.78	17.38	4
11	CDP3 with actionable Project Marinus Stage 2	13.37	15.74	2	17.35	17.45	1
3	*Step Change* least-cost DP	14.01	15.73	3	17.85	17.38	3
14	CDP3 with actionable Project Marinus Stage 2 and QNI Connect	13.32	15.73	4	17.25	17.42	2
7	CDP3 with actionable QNI Connect	13.96	15.72	5	17.79	17.36	5

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

In this sensitivity on *Step Change,* the worst weighted regrets associated with CDP13 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 CDP11 becoming second ranked. Other rankings remain robust to the sensitivity.

A6.7.7 Development of Pioneer-Burdekin Pumped Hydro Project

In the Draft 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 is treated as a potential new development candidate (distinct from the Borumba Dam Pumped Hydro, which is classified as an anticipated project).

This sensitivity explores 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[34]– 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 58.

Table 58 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**
11	CDP3 with actionable Project Marinus Stage 2	17.15	6.82	17.19	1	17.35	7.24	17.45	1
3	*Step Change* least-cost DP	17.68	6.83	17.13	2	17.85	7.25	17.38	3
8	CDP3 without actionable New England REZ Extension	17.55	7.01	17.11	3	17.78	7.44	17.38	4
14	CDP3 with actionable Project Marinus Stage 2 and QNI Connect	17.05	6.46	17.08	4	17.25	7.06	17.42	2
9	CDP3 with actionable Queensland SuperGrid North	17.63	6.49	17.04	5	17.50	6.70	17.07	8
7	CDP3 with actionable QNI Connect	17.58	6.47	17.03	6	17.79	7.07	17.36	5

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

CDP11 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 CDP9 – which develops the Queensland SuperGrid North project within its actionable window – to fifth best.

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. CDP14 and CDP7, which both develop QNI Connect in its actionable window, are relegated to worse rankings.

[34] 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.

To understand the impact of this sensitivity, Table 59 compares relevant CDPs against CDP3, 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 CDP9 under this sensitivity relative to other CDPs. While CDP9 delivers $311 million less weighted market benefits than CDP3 under core assumptions, this difference falls to just $93 million if Pioneer-Burdekin Pumped Hydro Project is developed.

Table 59 Change in net market benefits relative to CDP3 (in $ billion), Pioneer-Burdekin Pumped Hydro Project sensitivity and core assumptions

CDP	CDP description	Sensitivity	Benefits relative to CDP3		
			Step Change	***Progressive Change***	**WNMB**
CDP7	CDP3 with actionable QNI Connect	Core assumptions	-0.06	-0.18	-0.02
		Pioneer-Burdekin Pumped Hydro Project sensitivity	-0.10	-0.35	-0.11
CDP9	CDP3 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
CDP11	CDP3 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 CDP7 in this sensitivity ($105 million reduction in weighted net market benefits compared to CDP3) than under core assumptions (only $20 million worse off).

Finally, CDP11 remains robust to changing assumptions, with no change to its position as the top-ranked CDP for weighted net market benefits under this sensitivity.

A6.7.8 Development of Cethana Pumped Hydro Energy Storage

The Cethana pumped hydro energy storage project is a key long-duration storage (750MW, 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 is instead treated as a potential build candidate in the core scenarios. This sensitivity, applied to *Step Change* only, explores the impact on the key CDPs if Cethana became an anticipated project from 2032-33.

As seen in Table 60, the assumed development of the Cethana project has no impact on relative rankings for the top five CDPs. As discussed in A6.5.2, Tasmania is forecast to provide additional renewable energy and firming capacity with the development of Project Marinus, to reduce fuel costs within the mainland NEM regions. With Cethana assumed to develop, the difference in builds and build costs in Tasmania between an early development of Project Marinus Stage 2 (CDP11) and a delayed development of Stage 2 (CDP3) lessens, increasing the economic case for Stage 2's early development.

Table 60 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**
11	CDP3 with actionable Project Marinus Stage 2	17.77	17.63	1	17.35	17.45	1
14	CDP3 with actionable Project Marinus Stage 2 and actionable QNI Connect	17.68	17.61	2	17.25	17.42	2
3	*Step Change* least-cost DP	18.20	17.53	3	17.85	17.38	3
8	CDP3 without actionable New England REZ Extension	18.12	17.53	4	17.78	17.38	4
7	CDP3 with actionable QNI Connect	18.13	17.51	5	17.79	17.36	5

Note: As the sensitivity analysis were 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 CDP11 and CDP3 in *Step Change* reducing from $502 million under core assumptions to $430 million in this sensitivity.

A6.7.9 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*[35] 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%[36].

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

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

[36] 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

transmission project. A sensitivity that explores the lower bound of the cost accuracy range has not been explored.

As Table 61 shows, applying the top end of the cost ranges for transmission projects has an impact on the CBA. CDP3 and CDP8 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 CDP11 (which features Project Marinus Stage 2) is higher than the weighted net market benefits for CDP7 or CDP14 (which features QNI Connect), with the former now ranked third in weighted net market benefits, and second in worst weighted regrets.

Table 61 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**
3	*Step Change* least-cost DP	1	5	3	8
8	CDP3 without actionable New England REZ Extension	2	8	4	10
11	CDP3 with actionable Project Marinus Stage 2	3	2	1	3
7	CDP3 with actionable QNI Connect	6	1	5	4
14	CDP3 with actionable Project Marinus Stage 2 and actionable QNI Connect	8	7	2	1

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

This sensitivity sees a change in worst weighted regrets. CDP11 becomes second ranked (from third) but the regrets associated with CDP7 drops – becoming top-ranked in worst weighted regrets; and CDP14 becoming seventh instead of first. With increased transmission costs, the regrets associated with over-investment increases and the rankings of CDPs like CDP14, CDP13 and CDP1 fall, whereas the rankings of those CDPs with comparatively fewer actionable projects (CDP3, CDP11 or CDP7) increase.

A6.8 The impact of consumer risk preferences on transmission timings

Consumer Risk Preferences

AEMO has engaged directly with residential consumers ("consumers") for the Draft 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*[37].

It is important to note that AEMO has not applied the recently developed consumer risk preference metric estimate to select an ODP for the Draft 2024 ISP. In future, if AEMO selects an ODP that is not risk neutral, AEMO intends to use the metric to evaluate how the ODP performs to reduce volatility in the cost of future electricity bills. 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.

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

A6.9 The optimal development path

As discussed in Section A6.6, CDP11 is selected as the ODP, on the basis that it provides the highest weighted net market benefits. It also is a highly ranked CDP on a least worst-weighted regrets basis, being the third best CDP at minimising potential regrets. It therefore provides an appropriately balanced trade-off between benefits and risks of over- or under-investment across the scenario collection.

Additionally, the sensitivity analysis in Section A6.7 found that CDP11 is more resilient than most of the alternative CDPs considered across the sensitivity collection. For six of the ten sensitivities tested, CDP11 performed better than the other sensitivities on weighted net market benefits basis. Only in the sensitivities where a much faster transition away from coal generation is forecast (such as the *Lower Discount Rate* or *Rapid Decarbonisation* sensitivities) does CDP14 (which features additional QNI Connect) provide much higher benefits – see Table 62 below.

Table 62 Relativity of weighted net market benefits (in $ billion) for each key CPD across the sensitivity collection

CDP	Description	*Core scenarios*	*Rapid Decarbonisation*	*Reduced Energy Efficiency*	*Electrification Alternatives*	*Constrained Supply Chains*[A]	*Reduced Social Licence*	*Higher Discount Rate*	*Lower Discount Rate*	*Development of Pioneer-Burdekin Pumped Hydro*	*Development of Cethana PHES*	*Transmission cost uncertainty*
Weighted net market benefits												
3	*Step Change* least-cost DP	17.38	20.69	17.40	17.16	19.36	15.73	7.66	40.25	17.13	17.53	12.31
8	CDP3 without actionable New England REZ Extension	17.38	20.67	17.39	17.19	19.37	15.75	7.71	40.20	17.11	17.53	12.23
7	CDP3 with actionable QNI Connect	17.36	20.75	17.38	17.12	19.38	15.72	7.55	40.37	17.03	17.51	12.04
11	CDP3 with actionable Project Marinus Stage 2	17.45	20.95	17.50	17.23	19.47	15.74	7.73	40.42	17.19	17.63	12.17
14	CDP3 with actionable Project Marinus Stage 2 and actionable QNI Connect	17.42	21.02	17.48	17.19	19.47	15.73	7.60	40.53	17.08	17.61	11.96
Change in weighted net market benefits relative to the most beneficial CDP												
3	*Step Change* least-cost DP	-0.07	-0.32	-0.10	-0.07	-0.11	-0.02	-0.07	-0.27	-0.07	-0.10	-
8	CDP3 without actionable New England REZ Extension	-0.07	-0.35	-0.11	-0.04	-0.10	-	-0.02	-0.33	-0.08	-0.10	-0.07
7	CDP3 with actionable QNI Connect	-0.09	-0.27	-0.12	-0.11	-0.10	-0.04	-0.17	-0.16	-0.17	-0.12	-0.27
11	CDP3 with actionable Project Marinus Stage 2	-	-0.07	-	-	-	-0.01	-	-0.11	-	-	-0.13
14	CDP3 with actionable Project Marinus Stage 2 and actionable QNI Connect	-0.04	-	-0.03	-0.04	-0.00	-0.02	-0.13	-	-0.11	-0.03	-0.35

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 produce the most benefits 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 within 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.

Another potentially beneficial early-investment project – QNI Connect – as explored in CDP14, reduces net market benefits relative to CDP11 in both *Step Change* and *Progressive Change*. While it is better-ranked in *Green Energy Exports,* the potential development of the Pioneer-Burdekin Pumped Hydro Project would reduce the benefits from early development of this project and would prefer infrastructure to support the Queensland SuperGrid North instead. As such, AEMO considers it would not be prudent to include the additional investment in QNI Connect within the actionable projects of the ODP.

Given its robust performance across the set of alternative assumptions tested, AEMO identifies CDP11 as the optimal development path.

Table 63 presents the set of projects identified as actionable in this Draft 2024 ISP. More detail on each of these projects can be found in Appendix 5.

Table 63 Actionable projects in the draft optimal development path

Already actionable projects (confirmed in this Draft ISP as continuing to be actionable)	**In service timing advised by proponent**	**Full capacity timing advised by proponent**	**Actionable framework**
HumeLink	Northern Circuit July 2026 Southern Circuit December 2026	Northern Circuit July 2026 Southern Circuit December 2026	ISP
Sydney Ring *(Hunter Transmission Project and investigation of southern network options)*	December 2027	December 2027	NSW[A]
New England REZ Transmission Link	September 2028	September 2028	NSW[A]
Victoria – New South Wales Interconnector West (VNI West)	December 2028	December 2029	ISP
Project Marinus[B]	Stage 1 June 2030 Stage 2 June 2032	Stage 1 December 2030 Stage 2 December 2032	ISP
Newly actionable projects (as identified in this Draft ISP)	**In service timing advised by proponent**	**Full capacity timing advised by proponent**	**Actionable framework**
Gladstone Grid Reinforcement	September 2029	September 2029	QLD[C]
Queensland SuperGrid South	June 2031	June 2031	QLD[C]

Note. Details of these projects are found in Appendix 5 of this Draft 2024 ISP
A. 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. Includes additional scope compared to 2022 ISP.
B. Project Marinus includes Marinus Link as well as the North West Transmission Developments projects in Tasmania. Project proponent date represents a modelling date and is subject to further refinement.
C. These are actionable Queensland projects rather than actionable ISP projects. They are intended to progress under the *Energy (Renewable Transformation and Jobs) Bill* 2023 (Qld) rather than the ISP framework. Project proponent dates are earliest in-service dates and are subject to further refinement.

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 Australian Energy Regulator's (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.

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

Term	Acronym	Explanation
Renewable energy	-	For the purposes of the ISP, the following technologies are referred to under the grouping of renewable energy: “solar, wind, biomass, hydro, and hydrogen turbines”. Variable renewable energy is a subset of this group, explained below.
Renewable energy zone	REZ	An area identified in the ISP as high-quality resource areas where clusters of large-scale renewable energy projects can be developed using economies of scale.
Renewable drought	-	A prolonged period of very low levels of variable renewable output, typically associated with dark and still conditions that limit production from both solar and wind generators.
Scenario	-	A possible future of how the NEM may develop to meet a set of conditions that influence consumer demand, economic activity, decarbonisation, and other parameters. For the 2024 ISP, AEMO has considered three scenarios: *Progressive Change*, *Step Change* and *Green Energy Exports*.
Secure (power system)	-	The system is secure if it is operating within defined technical limits and is able to be returned to within those limits after a major power system element is disconnected (such as a generator or a major transmission network element).
Sensitivity analysis	-	Analysis undertaken to determine how modelling outcomes change if an input assumption (or a collection of related input assumptions) is changed.
Spilled energy	-	Energy from variable renewable energy resources that could be generated but is unable to be delivered. Transmission curtailment results in spilled energy when generation is constrained due to operational limits, and economic spill occurs when generation reduces output due to market price.
Transmission network service provider	TNSP	A business responsible for owning, controlling or operating a transmission network.
Utility-scale or utility		For the purposes of the ISP, ‘utility-scale’ and ‘utility’ refers to technologies connected to the high-voltage power system rather than behind the meter at a business or residence.
Virtual power plant	VPP	An aggregation of resources coordinated to deliver services for power system operations and electricity markets. For the ISP, VPPs enable coordinated control of CER, including batteries and electric vehicles.
Variable renewable energy	VRE	Renewable resources whose generation output can vary greatly in short time periods due to changing weather conditions, such as solar and wind.