Appendix 6. Cost benefit analysis

December 2021

Appendix to Draft 2022 ISP for the National Electricity Market

Important notice

Purpose

This is Appendix 6 to the Draft 2022 *Integrated System Plan* (ISP), available at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp.

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Version control

Version	Release date	Changes
1	10/12/2021	Initial release.

Draft ISP Appendices

Contents

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A6.1 Introduction

Section 6 of the Draft ISP sets out the process and rationale for identifying the ODP from a range of CDPs.

This appendix details the cost-benefit analysis of those CDPs, across the four ISP scenarios, following the approach set out in AEMO's ISP Methodology[1]. The appendix:

- A6.2: Provides a summary of the overall approach to the CBA assessment, and additional information to assist in interpreting the outcomes presented in this appendix.
- A6.3: Steps through the process and outcomes of the determination of the least-cost development path in each scenario.
- A6.4: Outlines the set of CDPs which have been developed based on the least-cost development paths.
- A6.5: Provides a detailed assessment of these candidates.
- A.6.6: Explores the risks and benefits of actionable project timings.
- A6.7: Tests the resilience of the CDPs to several sensitivities.

In this appendix, all dates are indicative, and on a financial year basis. For example, 2023-24 represents the financial year ending June 2024. All values presented are 30 June 2021 real dollars unless stated otherwise. NPV outcomes are discounted back to 30 June 2021 by applying the relevant discount rate. All NPV values consider the ISP horizon, from 2023-24 to 2050-51.

This appendix is supported by the Generation Outlook files, which also provide a breakdown of the difference in system costs between alternative CDPs.

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

A6.2 Approach to the cost benefit analysis

A6.2.1 The ISP approach to cost benefit analysis

This Draft ISP applies AEMO's ISP Methodology which details the approach used for the cost benefit analysis (CBA) which underpins AEMO's determination of the Draft ODP. This includes:

- Setting out the principles that govern the cost benefit analysis.
- The quantification of costs and market benefits, including the classes of market benefits that have been considered by AEMO in the ISP.
- The determination of the least-cost Development Path (DP) for each scenario.
- The process for building CDPs.
- How the CDPs are assessed across all scenarios.
- The evaluation of net market benefits compared to a counterfactual DP.
- How CDPs are ranked according to weighted net market benefits and least-worst weighted regrets (LWWR).
- Finalising the Draft ODP through sensitivity analysis.

The key terminology used throughout this section is as follows:

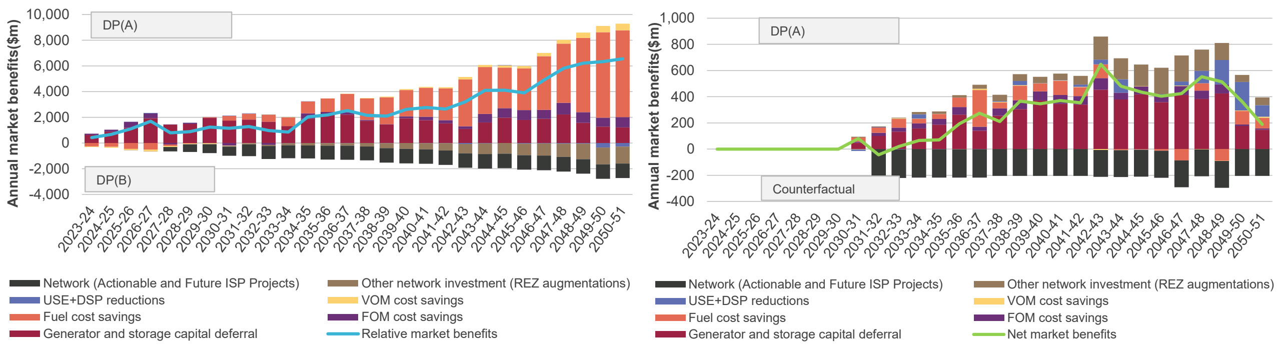
- The **earliest in-service date (EISD)** of a project is the earliest date the project can be completed (including commissioning and interregional testing as appropriate).
- **Actionable ISP projects** are projects that require a Project Assessment Draft Report (PADR) to be completed within 24 months of the ISP publication. As such, a project is identified as actionable where the CBA has concluded that the project should proceed at the EISD (or EISD + 1 given the two-year cycle of the ISP), or else the project's PADR should be commenced after the following ISP has reassessed its benefits.
- **Future ISP projects** are defined in the NER as those projects which address an identified need, form part of the ODP, and may be actionable ISP projects in the future. As such, a future ISP project is identified where the CBA has concluded that the project should proceed after the EISD.
- ***Potential* actionable and future ISP projects** share the definitions outlined above, except these concepts appear before the determination of the ODP.
- **Development Paths (DPs)** are defined in the NER as a set of projects (actionable projects, future projects, and development opportunities) that together address power system needs. For the purposes of assessing the CBA, DPs refer to a combination of ISP projects that enable development opportunities. DPs are not scenario-specific, as they can be imposed and modelled for more than one scenario. DPs are not necessarily optimal in any scenario – many DPs are generally required to be tested to determine which is optimal in any given scenario.
- A **Candidate Development Path (CDP)** represents a collection of DPs which share a set of potential actionable projects. The timings of potential future ISP projects are then allowed to vary across scenarios depending on the needs of a given scenario.

- The **Optimal Development Path (ODP)** is chosen from the set of CDPs as the suite of actionable and future ISP projects which optimises benefits to consumers given the uncertainties in the future outlook. In the context of the CBA, the ODP is referring to the collection of ISP projects – the transmission projects that enable the ISP development opportunities in generation and storage assets, whereas the draft and final ODP include these development opportunities alongside the ISP (transmission) projects.
- The **counterfactual development path** represents a DP with no future network augmentation other than committed and anticipated projects, or small intra-regional augmentations and replacement expenditure projects. It forms the basis on which all other DPs are compared within each scenario.
- An **ISP development opportunity** means a development identified in an ISP that does not relate to a transmission asset or non-network option and may include distribution assets, generation, storage projects or demand side developments that are consistent with the efficient development of the power system.
- **Net present value (NPV)** is the discounted sum of all costs and is used to determine the discounted total system cost of each DP.

A6.2.2 Interpreting the graphics in this appendix

The appendix presents a number of charts comparing the projected benefits over time of two different development paths, as shown in the example figure below. Some of the comparisons are relative to a counterfactual, in which case benefits are referred to as net market benefits. When comparing across DPs, benefits are referred to as relative market benefits.

Figure 1 Example interpretation of net and relative market benefits used in the Appendix



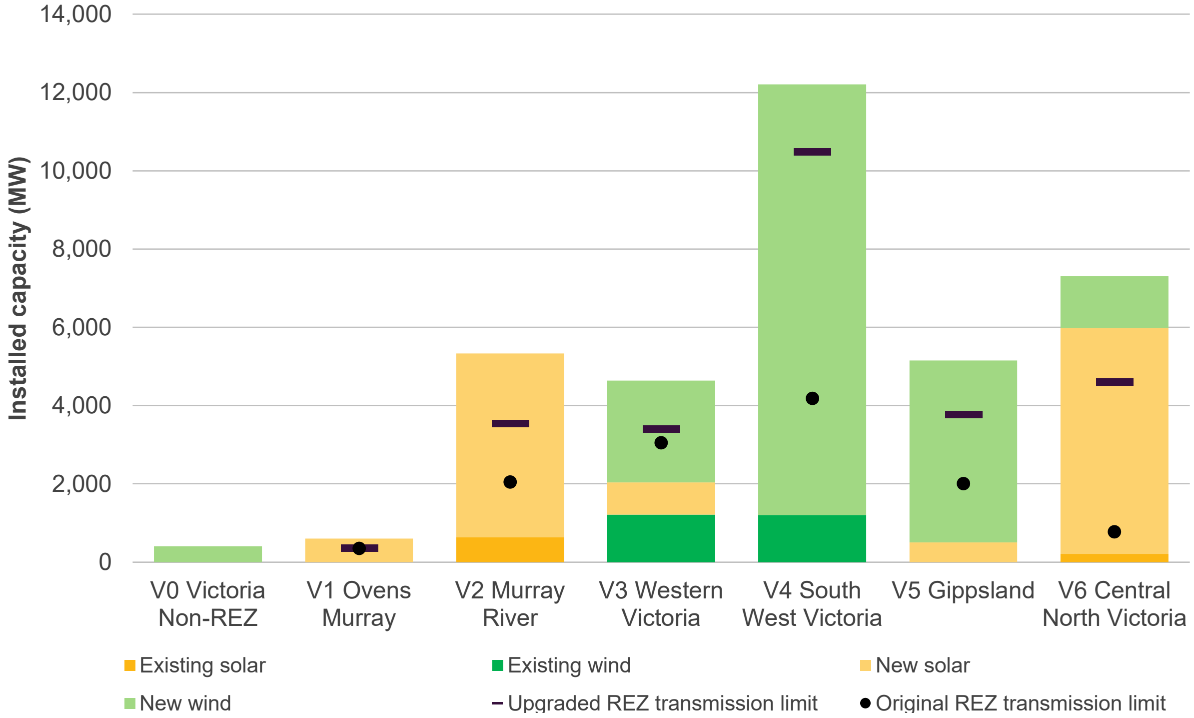
Interpreting Figure 1:

- The stacked columns illustrate the projected values for different classes of market benefit on an annual basis. A positive value indicates the benefits (that is, cost savings) associated with DP(A) relative to DP(B) – which in some cases is the counterfactual – and a negative value indicates the additional costs incurred compared to DP(B). For example, the orange and red bars represent fuel cost savings and generation capital deferral cost savings in DP(A), while the black stacked column indicates greater transmission costs in this CDP compared to DP(B) (or counterfactual).
- The blue (green) line represents the projected annual net market benefits of DP(A) over DP(B) (or the counterfactual, if green). Where the line is above the x-axis, DP(A) delivers positive net market benefits

relative to DP(B). Conversely, where the line is below the x-axis, DP(A) delivers negative net market benefits relative to DP(B).

The appendix also presents figures intended to demonstrate both generation and network developments for REZs. An example figure is shown in Figure 2 for Victoria.

Figure 2 Example interpretation of REZ developments used in this appendix



Interpreting Figure 2:

- The stacked columns illustrate the forecast wind and solar capacity developments in each REZ by a given year. The stacked columns also show the breakdown of exiting wind and solar capacity within the total capacity.
- The black dot represents the assumed existing REZ transmission limit (at times the existing limit includes committed augmentations, further detail is provided in Section 3.9 of the 2021 IASR[2].
- The black line represents the REZ transmission limit in the future year, which includes any augmentations that add to the existing limit.
- If the installed capacity is higher than its transmission limits for any REZ, it indicates that there may be VRE curtailment at times, depending on the correlation of resources within the REZ and the likelihood that all installed VRE capacity will be available at any given time.

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

A6.2.3 Application of scenario weightings to net market benefits and regrets

The weightings applied to the four ISP scenarios were determined through a Delphi process (see Appendix 1).

The scenario weights applied in the CBA analysis are shown in Table 1. These scenario weightings are used to allow comparison of CDPs across the set of scenarios and are applied to both net market benefits and regrets for the purpose of ranking these CDPs.

Table 1 Scenario weightings applied in CBA analysis

Scenario	Weighting
Step Change	50%
Progressive Change	29%
Hydrogen Superpower	17%
Slow Change	4%

A6.2.4 Consideration of additional benefits through time-sequential modelling

AEMO relies on the capacity outlook model (described in detail in the ISP Methodology) as the primary means to produce the development paths and quantify the various classes of cost which are used to determine net market benefits. The capacity outlook model makes necessary compromises in terms of granularity as a means of managing simulation time, and also does not utilise stochastic methods to determined USE.

The time-sequential model is deployed to validate and verify the developments identified in the capacity outlook model. It also is used to assist in informing economic coal closures for the first 10 years of the modelled horizon in the *Progressive Change* scenario, as per the ISP Methodology, which states that revenue adequacy modelling would be used in scenarios that do not have explicit carbon budgets.

Where it has been deemed potentially material, AEMO has utilised time-sequential modelling to support the comparison of key CDPs, focusing on the *Step Change* and *Progressive Change* scenarios. Where these benefits have been quantified, the horizon has been limited to the first 10 years after the commissioning of the first potential actionable ISP project: 2026-27 to 2035-36.

Additional reliability cost savings

Time-sequential modelling, which incorporates more granular detail and stochastic outages, can result in greater forecast levels of USE than are forecast in the capacity outlook models, while still remaining below the reliability standard. As such, a comparison between two CDPs through time-sequential modelling can indicate a greater level of reliability benefits provided by differences in network, generation, and storage investment.

Where AEMO considers that it might be material to the outcome of the DP, additional reliability cost savings are determined by comparing USE between CDPs, with any difference in USE valued at the value of customer reliability. In these instanced, any reliability cost savings that are present in the capacity outlook modelling are deducted from the cost savings determined through time-sequential modelling to ensure no double counting of benefit classes.

The supplementary Generation Outlook files do not include any impact of additional reliability cost savings.

Competition benefits

For a small subset of CDPs, indicative competition benefits have been presented for information only[3]. Only competition cost savings have been considered, calculated according to a modified version of the methodology outlined in EY's Competition Benefits Inputs Assumptions and Methodology Report[4].

Any total system cost and net market benefits provided in this appendix, or in the main report, exclude these additional benefits.

The supplementary Generation Outlook files do not include any impact of competition benefits.

[3] For further details on AEMO's consideration of competition benefits and responses to the feedback received from stakeholders, see https://aemo.com.au/consultations/current-and-closed-consultations/competition-benefits-in-the-isp.

[4] As an outcome of consultation, AEMO made an adjustment to this methodology to adopt the distinct capacity expansion plans for each of a CDP and its counterfactual development plan. See https://www.aemo.com.au/consultations/current-and-closed-consultations/competition-benefits-in-the-isp.

A6.3 Determining the least-cost development path for each scenario

The first stage in the CBA process is to determine the DP that maximises net market benefits for consumers in each scenario, assuming perfect foresight (the least-cost DP). The determination of the least-cost DP within each scenario was based on testing hundreds of network development combinations and permutations which vary with respect to the candidate transmission options and timings of those developments. Each DP tested resulted in a different development of generation, storage, and transmission to facilitate REZ development. The resulting NPVs of total system costs were then compared to identify the DP that delivers the necessary infrastructure developments as efficiently as possible (by minimising these total system costs).

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

- The results of the Single-Stage Long-Term Model[5] (SSLT) are used to inform which transmission flow paths are likely to benefit from augmentation, as well as an indication of timing and scale.
- Many DPs are simulated which test whether any of the available flow path augmentation options deliver positive net market benefits.
- Various options are then compared to a DP that does not have that option to identify a “cross-over point” at which it appears the project is starting to deliver positive net market benefits. Alternative timings are then tested around this point to determine which is an optimal timing.
- This process is then repeated to include other ISP projects where there is a logical interaction, to understand what combination of projects and/or project timings delivers the highest net market benefits in each scenario.
- Additional augmentations are included to confirm that they do not provide any further increase in net market benefits.

The details in this section present a much more concise summary of this process by comparing the least-cost DP to a small subset of DPs that differ in a way that illustrates why the identified DP is optimal in that scenario. This includes consideration of alternative projects or project routes to demonstrate that these have been considered and why they were not optimal.

This section does not discuss in detail the potential early timings of major projects, as these are explored in more detail through the assessment of CDPs in Section A6.5.

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

Table 2 presents the network development timings in the least-cost DP for *Step Change*, along with a subset of alternative DPs. The sample alternative DPs selected and contrasted below demonstrate:

- Why the VNI West (via Kerang) route has been selected over the VNI West (via Shepparton) route (DP1).
- The benefits provided by a Gladstone Grid Reinforcement (DP2).
- The magnitude of market benefits delivered by both stages of Marinus Link (DP3).
- The benefits provided by a timely HumeLink delivery (DP4).

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

Table 2 Examples of developments paths assessed in *Step Change*

Network option	Least-cost DP	Alternative DP1	Alternative DP2	Alternative DP3	Alternative DP4
Gladstone Grid Reinforcement	2030-31	2030-31	-	2030-31	2030-31
Central to Southern QLD Stage 1	2028-29	2028-29	2028-29	2028-29	2028-29
Central to Southern QLD Stage 2	2038-39	2038-39	2038-39	2038-39	2038-39
QNI Connect	2032-33	2032-33	2032-33	2032-33	2032-33
New England REZ Transmission Link	2027-28	2027-28	2027-28	2027-28	2027-28
New England REZ Extension	2035-36	2035-36	2035-36	2035-36	2035-36
Sydney Ring	2027-28	2027-28	2027-28	2027-28	2027-28
HumeLink	2028-29	2028-29	2028-29	2028-29	2035-36
VNI West (via Kerang)	2031-32	-	2031-32	2031-32	2031-32
VNI West (via Shepparton)	-	2031-32	-	-	-
Marinus Link (Cable 1)	2027-28	2027-28	2027-28	-	2027-28
Marinus Link (Cable 2)	2029-30	2029-30	2029-30	-	2029-30
Reduction in net market benefits ($ million)	-	-93	-1,180	-4,800	-361

Comparing options for the VNI West development

Alternative DP1 explores the benefits of choosing an alternative VNI West option via Shepparton instead of developing the option via Kerang, with all other projects remaining the same as the least-cost DP.

Both VNI West options provide the same amount of additional transfer along the Victoria to Southern New South Wales flow path and have similar capital costs, with the option via Shepparton assumed to be slightly lower cost. The key difference between these options, and what Alternative DP1 aims to explore the benefits of, is the difference in routes leading to the upgrading in hosting capacity of different REZs. While both options provide an additional 550 MW of hosting capacity to the Western Victoria REZ, the Kerang route upgrades Murray River by 1,600 MW whereas the Shepparton route upgrades Central North Victoria by 1,050 MW.

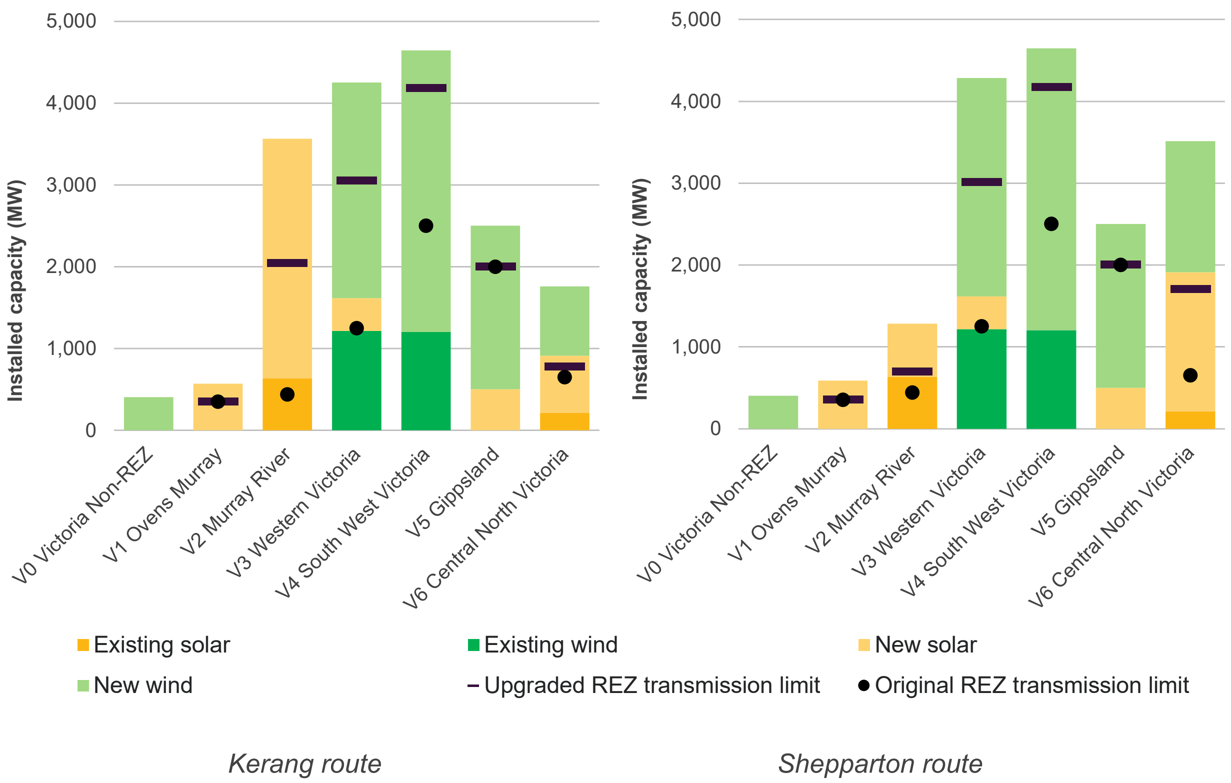
Table 3 shows the benefits of developing VNI West via Kerang rather than via Shepparton, demonstrating that most of the benefits of the Kerang route are in generator capital cost and REZ augmentation cost savings. These savings come with having access to the better renewable resource in Murray River compared to Central North Victoria, and the additional hosting capacity provided being greater in magnitude, meaning less is spent on building generation capacity and augmenting other REZs to meet demand.

Table 3 Relative benefits of the least-cost DP by category compared to Alternative DP1 with VNI West (via Shepparton), *Step Change* scenario

Class of market benefit	Relative benefit (NPV, $ million)
Generator and storage capital deferral	139
FOM cost savings	-14
Fuel cost savings	15
VOM cost savings	-1
USE+DSP reductions	1
Other Network investment (REZ augmentations)	64
Gross market benefits	204
Network (Actionable and Future ISP Projects)	-112
Total net market benefits	93

Figure 3 below shows the different builds in Victorian REZ developments by 2044-45 resulting from choosing the Kerang route or the Shepparton route.

Figure 3 Victorian REZ developments by 2044-45 with different VNI West options (Kerang route compared to Shepparton route), *Step Change*



With access to an additional 1,600 MW of hosting capacity (an increase in the REZ transmission limit as a result of a line build) in the Murray River REZ with the Kerang route, over 2 GW of additional solar capacity is developed in the REZ, taking advantage of its strong solar resource.

In comparison, the Shepparton route unlocks more hosting capacity in Central North Victoria over its existing REZ transmission limit that is utilised to build a combination of solar and wind instead. This results in greater generator capital costs being incurred to supply a similar amount of energy, largely due to the higher capital cost of wind compared to solar and the differences in resource quality (based on inputs available to AEMO, see Sections 3.5 and 3.9 of the 2021 IASR).

If the Shepparton route is built, additional REZ augmentation costs are nevertheless incurred as a result of needing to increase the existing REZ transmission limit in Murray River beyond its existing hosting capacity to accommodate more solar build (without the benefit of the REZ transmission limit increase that comes with the Kerang option).

In a similar fashion, if the Kerang route is built instead, some REZ augmentation costs will be incurred to increase the hosting capacity of Central North Victoria over and above its existing limit.

Similar modelling was also done in other scenarios. In the scenarios with slower decarbonisation (*Slow Change* and *Progressive Change*), the benefits of the two VNI West options were also very similar, with the Kerang route marginally more beneficial. In *Hydrogen Superpower*, a subsequent augmentation along the Shepparton route is optimal in the 2040s.

Benefits of the Gladstone Grid Reinforcement project

After the retirement of Gladstone Power Station, further investments are required to continue to supply load within the Gladstone area. The delivery of the Gladstone Grid Reinforcement project reduces the need for further investment in gas generation that is otherwise needed to supply the load. This results in continued generator capital and fuel cost savings, as well as DSP and USE reductions. These benefits are shown in Table 4.

Table 4 Relative benefits of least-cost DP compared to Alternative DP2 without Gladstone Grid Reinforcement, *Step Change*

Class of market benefit	Relative benefit (NPV, $ million)
Generator and storage capital deferral	415
FOM cost savings	-22
Fuel cost savings	285
VOM cost savings	-10
USE+DSP reductions	384
Other Network investment (REZ augmentations)	343
Gross market benefits	1,395
Network (Actionable and Future ISP Projects)	-214
Total net market benefits	1,181

Benefits of delivering Marinus Link as soon as possible

The large reduction in market benefits in Alternative DP3 demonstrates the value that Marinus Link delivers, if built as soon as possible. Further detail on the value provided by Marinus Link in *Step Change* is provided in Section A6.5.2.

The need for a timely delivery of HumeLink

The Alternative DP4 explores the impact of delivering HumeLink later (2035-36) in accordance with the optimal timing in *Progressive Change*, while keeping all other projects the same as the least-cost DP.

Table 5 shows the benefits delivered by developing HumeLink at the optimal timing in *Step Change*, compared to Alternative DP4, demonstrating that most of the benefits are generator and storage capital deferral and (to a lesser extent) fuel cost saving. When HumeLink is delivered later as in the Alternative DP4, additional investments in predominantly long-duration storage are required to maintain power system reliability in New South Wales. Section A6.5.2 provides more detail on the benefits HumeLink provides in *Step Change.*

Table 5 Relative benefits of least-cost DP compared to Alternative DP4 with early HumeLink, *Step Change*

Class of market benefit	Relative benefit (NPV, $ million)
Generator and storage capital deferral	838
FOM cost savings	125
Fuel cost savings	196
VOM cost savings	18
USE+DSP reductions	-7
Other Network investment (REZ augmentations)	84
Gross market benefits	1,255
Network (Actionable and Future ISP Projects)	-894
Total net market benefits	361

Benefits of least-cost development path compared to counterfactual development path

The counterfactual DP refers to a DP without any further transmission augmentation, as explained in Appendix 2. Table 6 provides a breakdown of the classes of market benefit delivered by the least-cost DP compared to the counterfactual. This shows that avoided generator capital costs and avoided fuel costs represent the majority of the gross market benefits in *Step Change*.

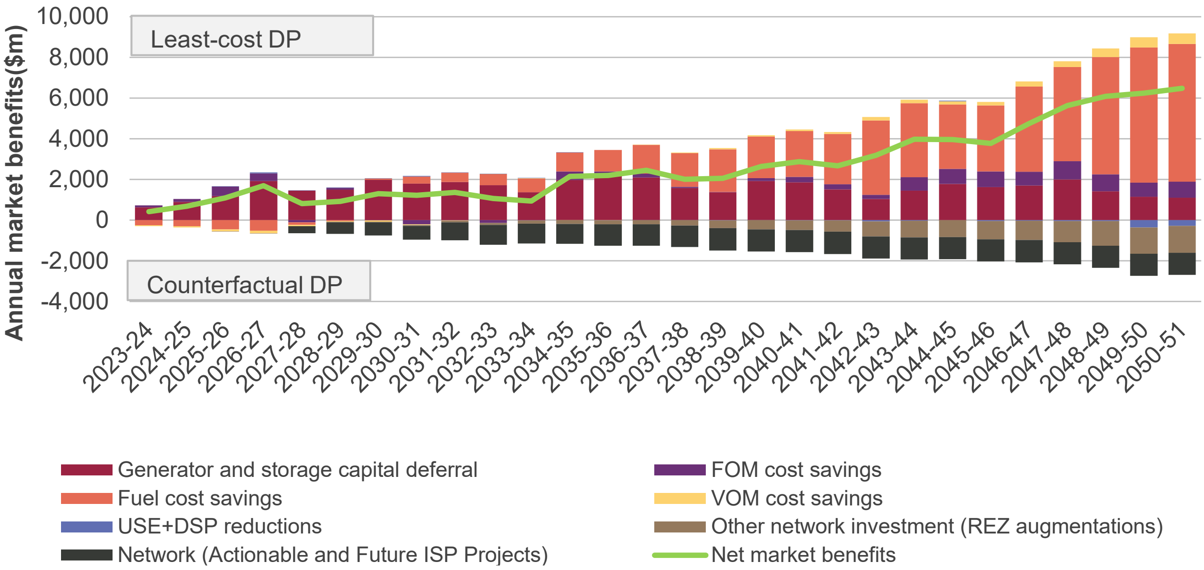
Table 6 Net market benefits of the least-cost DP by category, *Step Change*

Class of market benefit	Net benefit (NPV, $ million)
Generator and storage capital deferral	19,533
FOM cost savings	2,778
Fuel cost savings	15,205
VOM cost savings	361
USE+DSP reductions	-120
Gross market benefits	37,757
Network (Actionable and Future ISP Projects)	-8,686
Other Network investment (REZ augmentations)	-3,477
Total net market benefits	25,594

Figure 4 presents the annual net market benefits of the least-cost DP in the *Step Change* scenario. Net market benefits start accruing from the first year of the modelling horizon, initially due to avoided generator capital expenditure that is built in the counterfactual (in response to perfect foresight of early coal retirements). In the counterfactual DP, additional VRE and firming generation is required as a result of earlier coal retirements and transmission limitations. Over the period to 2035, the counterfactual sees more wind development across most NEM regions, followed by increased solar and storage development. The early investments in VRE and firming capacity are partly required to address the earlier coal retirements that take place in the counterfactual compared to the least-cost scenario, as described in Section A2.3.1 of Appendix 2.

From the mid-2030s, the counterfactual requires substantial gas generation development, including CCGT with CCS. This causes the avoided fuel costs benefits to increase throughout the modelling horizon. Towards the end of the horizon, offshore wind is also developed in the counterfactual given the limitations for onshore VRE development. Further comparisons of the capacity development and generation outcomes are provided in Appendix 2.

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



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

Table 7 presents the ISP project timings in the least-cost DP for the *Progressive Change* scenario with a subset of Alternative DPs. The sample of Alternative DPs selected below demonstrate:

- Why QNI Connect is a future project in the *Progressive Change* scenario, and the scale of benefits it delivers (DP1).
- Why the 500 kV New England options have been selected over a lower cost 330 kV augmentation (DP2).
- The magnitude of market benefits delivered by HumeLink (DP3).

Table 7 Examples of developments paths assessed in the *Progressive Change* scenario

Network option	Least-cost DP	Alternative DP1	Alternative DP2	Alternative DP3
Gladstone Grid Reinforcement	2035-36	2035-36	2035-36	2035-36
Central to Southern QLD Stage 1	2030-31	2030-31	2030-31	2030-31
Central to Southern QLD Stage 2	2038-39	2038-39	2038-39	2038-39
QNI Connect	2036-37	-	2036-37	2036-37
New England REZ Transmission Link	2027-28	2027-28	-	2027-28
New England REZ Extension	2038-39	2038-39	-	2038-39
CNSW-NNSW Option 7†	-	-	2027-28	-
CNSW – NNSW Option 9†	-	-	2038-39	-
CNSW – NNSW Option 10†	-	-	2046-47	-
Sydney Ring	2027-28	2027-28	2027-28	2027-28
HumeLink	2035-36	2035-36	2035-36	-
VNI West (via Kerang)	2038-39	2038-39	2038-39	2038-39
Marinus Link (Cable 1)	2030-31	2030-31	2030-31	2030-31
Marinus Link (Cable 2)	2032-33	2032-33	2032-33	2032-33
Reduction in net market benefits ($ million)	-	- 819	-712	-844

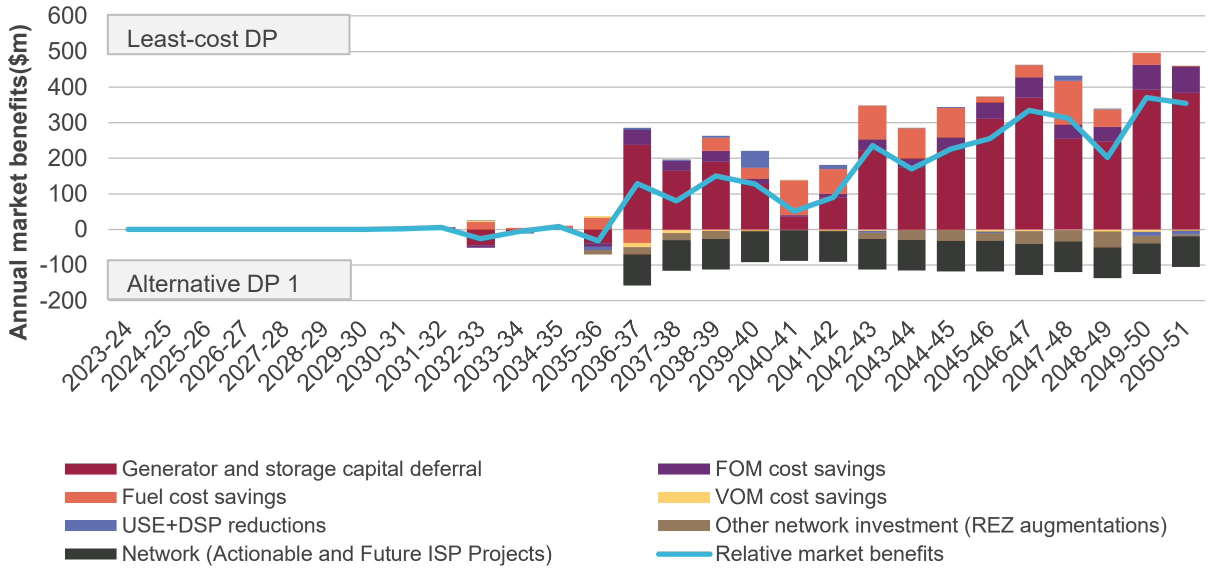
† Further details can be found in the "Augmentation options" tab in the Inputs and Assumptions workbook that accompanies the IASR, available at: https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios. These are alternative options to augment New England REZ to Central New South Wales.

The benefits of strengthening interconnection between Queensland and New South Wales

The Alternative DP1 aims to demonstrate the impact of augmenting the existing interconnection between New South Wales and Queensland (QNI) with QNI Connect.

The annual cost comparison between the least-cost DP and Alternative DP1 is presented in Figure 5.

Figure 5 Relative market benefits of the least-cost development path relative to the Alternative DP1



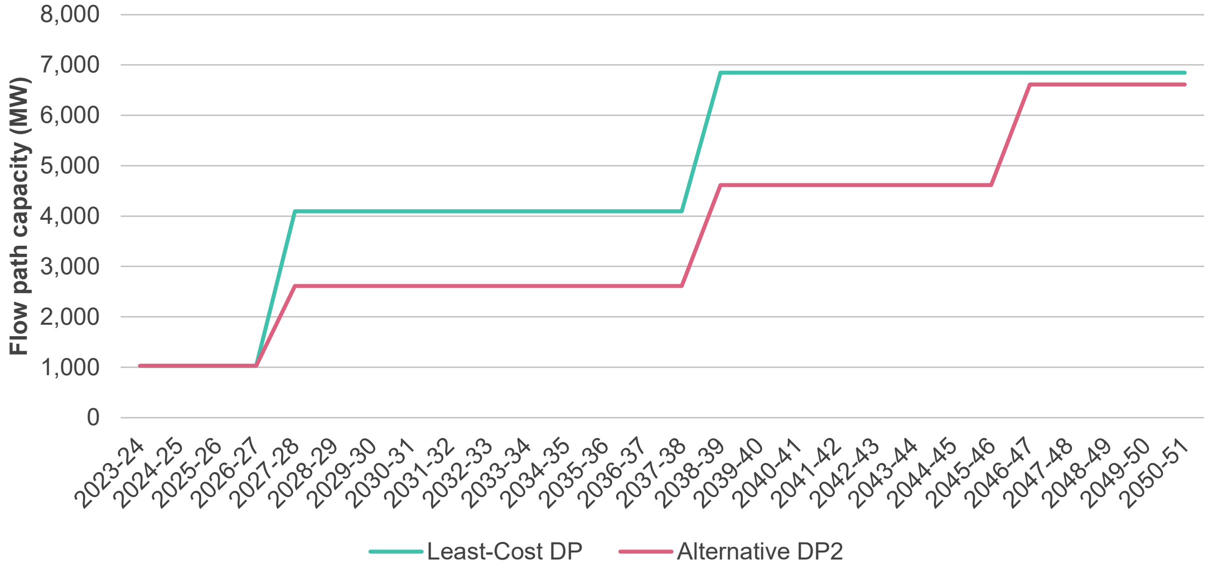
The main benefit of augmenting QNI is capital deferral. Augmenting QNI helps to deliver additional firm capacity to both New South Wales and Queensland as existing generation retires, reducing the need for additional investments in storage, pumped hydro, and peaking gas in those regions.

Long-term value provided by 500 kV augmentation to New England

The Alternative DP2 presents an alternative pathway to augmenting capacity to the New England REZ (named CNSW-NNSW Option 7, 9, and 10 – which includes a 330 kV augmentation and two HVDC options[6]).

Figure 6 compares the flow path capacity from Northern to Central New South Wales for the least-cost DP and Alternative DP2.

Figure 6 Flow path capacity from NNSW-CNSW for Least-cost DP and Alternative DP2

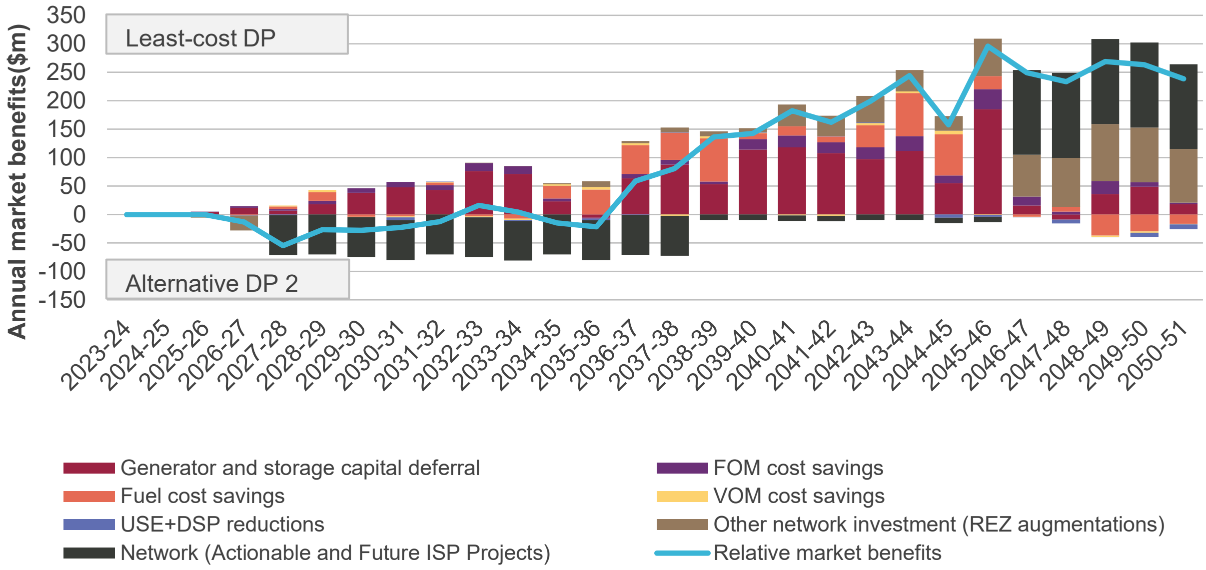


Both suites of augmentation options deliver approximately the same additional transfer capacity between Northern and Central New South Wales by 2046-47. However, augmentations in DP2 are delayed in comparison to the least-cost DP due to the higher costs of the subsequent augmentations.

The earlier development of this flow path in the least-cost DP increases access to the New England REZ, which ultimately allows for the better utilisation of high-quality VRE and delivers both capital deferral and fuel cost savings. The net market benefits of choosing the New England REZ Transmission Link and the New England REZ Extension over the Alternative DP2 are presented in Figure 7.

[6] Further details can be found in the "Augmentation options" tab in the Inputs and Assumptions workbook that accompanies the IASR, at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

Figure 7 Relative market benefits of the least-cost development path relative to the Alternative DP2



Network development options are designed to increase network capacity over time. Unless otherwise stipulated (such as staged projects), AEMO typically considers that network options used to develop the same portion of a network are mutually exclusive. This is because the transfer limits and the cost for the network development options are determined independently from other options. Building a combination of options will not necessarily result in the transfer gain of the sum of their parts. Similarly, the cost of augmentation options may vary if a different option is delivered first, due to scope overlap.

It shows that initially the less expensive 330 kV option is more cost-effective than the 500 kV option. However, from the mid-2030s, 500 kV options that form part of the least-cost DP start to produce greater benefits due to the greater access to the New England REZ. The subsequent HVDC augmentations that are available in addition to the 330 kV option are significantly more expensive than the additional capacity offered by the developments available in the least-cost DP.

From 2038-39, the transmission investment cost is roughly equivalent, however the least-cost DP delivers a larger augmentation which continues to provide benefits through avoided generator capital costs. After the further HVDC augmentation in 2046-47 in Alternative DP1, the transmission capacity differences are more minor and the dominant source of market benefits for the least-cost DP are the avoided network costs. Essentially, the least-cost DP is a lower cost way to deliver similar benefits by the end of the ISP horizon. Building the cheaper 330 kV option now may provide short-term gain, but be more costly in the longer term.

The REZ augmentation cost savings are due to the increased access to better renewable resources in New England, rather than North West New South Wales REZ (which is more liberated by one of the HVDC options available). The Alternative DP2 shifts the REZs developments from New England to North West NSW, building additional solar capacity in the REZ.

Benefits of HumeLink in *Progressive Change*

The Alternative DP3 illustrates the additional costs that are incurred when HumeLink is not developed compared to the optimal timing in the least-cost DP in *Progressive Change*. The sources of market benefits are similar to those described in Section A6.3.1, and explored in further detail in Section A6.5.2. The classes of market benefits attributable to the optimal HumeLink timing in *Progressive Change* are provided in Table 8. These results reinforce the point that HumeLink is beneficial in all scenarios, it is just a question of when.

Table 8 Relative benefits of least-cost DP compared to Alternative DP3, *Progressive Change*

Class of market benefit	Net benefit (NPV, $ million) of HumeLink
Generator and storage capital deferral	1,500
FOM cost savings	214
Fuel cost savings	259
VOM cost savings	10
USE+DSP reductions	3
Other Network investment (REZ augmentations)	-9
Gross market benefits	1,976
Network (Actionable and Future ISP Projects)	-1,132
Total net market benefits	844

Benefits of least-cost development path compared to counterfactual development path

Table 9 provides a breakdown of the classes of market benefit delivered by the least-cost DP compared to the counterfactual DP in *Progressive Change*. Generator capital costs and fuel costs savings represent 41% and 53% respectively of the gross market benefits of the *Progressive Change* least-cost DP, as shown in Table 9.

Table 9 Net market benefits of the least-cost development path by category, *Progressive Change* (NPV)

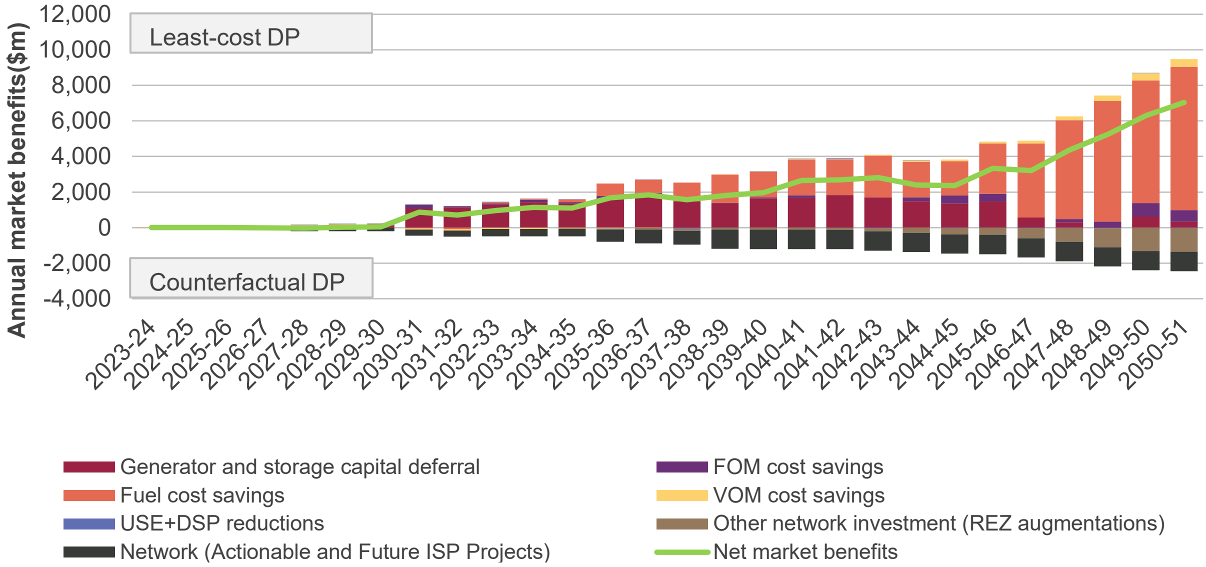
Class of market benefit	Net benefit ($ million)
Generator and storage capital deferral	10,070
FOM cost savings	1,233
Fuel cost savings	13,211
VOM cost savings	274
USE+DSP reductions	16
Gross market benefits	24,804
Network (Actionable and Future ISP Projects)	-6,331
Other Network investment (REZ augmentations)	-1,757
Total net market benefits	16,717

Figure 8 presents the annual net market benefits of the least-cost DP in *Progressive Change*. Significant benefits start to accrue from 2031 onwards due to avoided generator and storage capital investments. In the early 2030s, the additional capital costs in the counterfactual DP are primarily new VRE. Beyond 2030, avoided capital costs are increasingly due to additional investment in the counterfactual in firming generation, including mid-merit gas and in the later years, offshore wind. Appendix 2 provides further analysis on the differences in generation and storage development between the least-cost optimal and counterfactual DPs.

From the mid-2030s, avoided fuel costs begin to grow, and by 2040 represent the largest component of net benefit. Sensitivity analysis on the impact of gas prices to this assessment, as well as to the ranking of CDPs is provided in Section A6.7.1.

It is also evident that the size of net market benefits compared to the counterfactual DP increase throughout the modelling horizon and are very large by the 2050-51. Section A6.7.2 discusses the impact of a higher discount rate assumption.

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



A6.3.3 Least-cost development path for *Hydrogen Superpower*

The least-cost DP in *Hydrogen Superpower* and two alternative options are presented in Table 10.

This scenario requires the augmentation of many of the key flow paths in the NEM, as well as very large development of REZs to meet the lowest emissions budget of all scenarios, at the same time as meeting additional electricity demand to produce hydrogen.

The example set of alternative paths below demonstrate:

- The market benefit reduction of having the VNI West (via Kerang) late in this scenario (DP1).
- The magnitude of market benefits delivered by the Bayswater to Newcastle port augmentation (DP2).

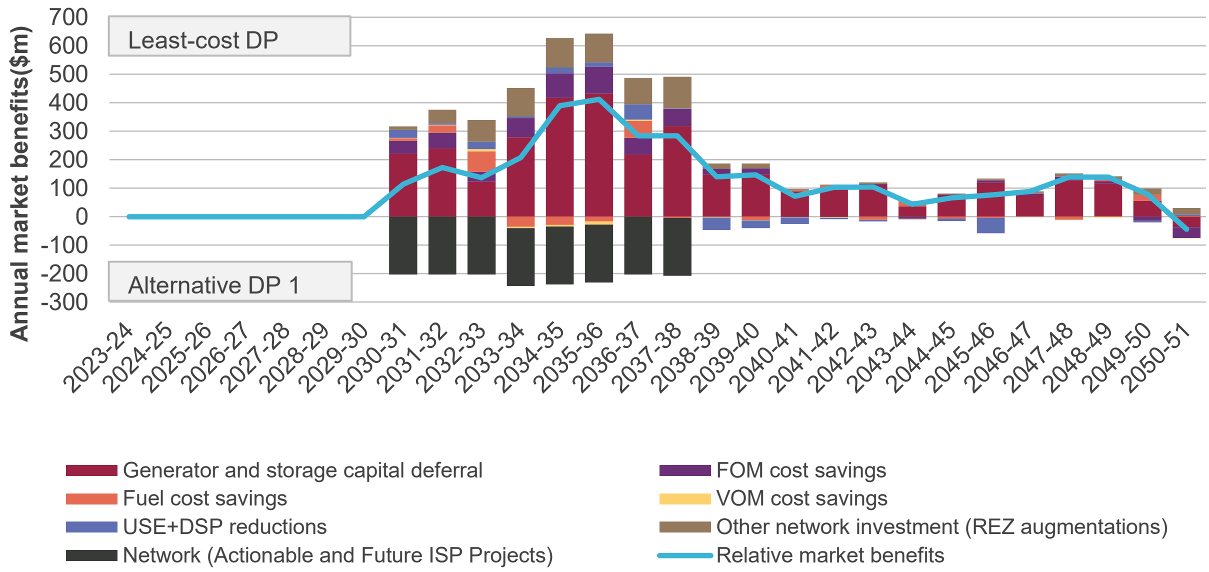
Table 10 Examples of development paths for *Hydrogen Superpower* Scenario

ISP Project	Least-cost DP	Alternative DP1	Alternative DP2
Gladstone Grid Reinforcement	2028-29	2028-29	2028-29
Central to Southern QLD Stage 1	2028-29	2028-29	2028-29
Central to Southern QLD Stage 2	2030-31	2030-31	2030-31
QNI Connect	2029-30	2029-30	2029-30
QNI Connect (Stage 2)	2030-31	2030-31	2030-31
New England REZ Transmission Link	2027-28	2027-28	2027-28
New England REZ Extension	2031-32	2031-32	2031-32
CNSW – NNSW Option 9	2042-43	2042-43	2042-43
Sydney Ring	2027-28	2027-28	2027-28
HumeLink	2027-28	2027-28	2027-28
VNI West	2030-31	2039-40	2030-31
VNI Option 6	2045-46	2045-46	2045-46
Marinus Link (Cable 1)	2027-28	2027-28	2027-28
Marinus Link (Cable 2)	2029-30	2029-30	2029-30
Bayswater to Newcastle port augmentation	2040-41	2040-41	-
Reduction in net market benefits ($ million)	-	-1,283	-4,352

VNI West is critical in *Hydrogen Superpower*

The Alternative DP1 illustrates the cost of having VNI West (via Kerang) later in the horizon. Figure 9 compares the market benefit of Alternative DP1 relative to the least-cost DP in *Hydrogen Superpower*.

Figure 9 Relative market benefits of the least-cost development path relative to the Alternative DP1 in the *Hydrogen Superpower* Scenario



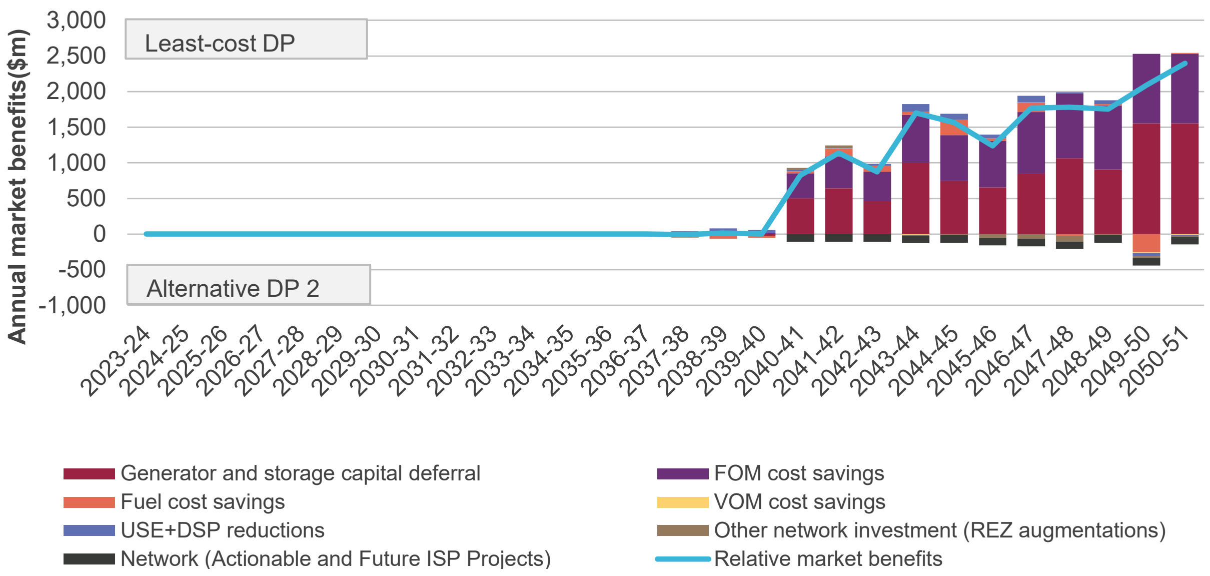
The total relative market benefit reduction of $1.3 billion is due to capital deferral and FOM cost savings. With VNI West at an earlier timing, there are comparatively fewer investments in new large-scale storage and VRE needed in Victoria, which results in substantial cost savings.

Benefits delivered by the Bayswater to Newcastle port augmentation

The Alternative DP2 assesses the impact of not developing the Bayswater to Newcastle port augmentation in the *Hydrogen Superpower* scenario. This augmentation provides greater transfer capacity to supply electrolyser load within the Sydney, Newcastle, Wollongong area, and is limited to this scenario only given the lack of export hydrogen development in other scenarios.

Figure 10 provides the annual net market benefits of the least-cost development path relative to DP2. The net benefit of developing the augmentation is $4.4 billion, mainly generator capital and FOM cost savings.

Figure 10 Relative market benefits of the least-cost development path relative to the Alternative DP2 in the *Hydrogen Superpower* Scenario



The generator capital cost and FOM savings in the least-cost DP come from avoiding additional storage and offshore wind investments (assumed to have a higher FOM component) in New South Wales, particularly in the Sydney, Newcastle, Wollongong area to meet the increase in hydrogen electrolyser load in the 2040s.

Benefits of the least-cost development path compared to the counterfactual development path in the *Hydrogen Superpower* Scenario

Table 11 provides a summary of the total net market benefits of the least-cost DP relative to the counterfactual. The total net market benefits are almost $70 billion, with the primary source of benefits being avoided capital expenditure.

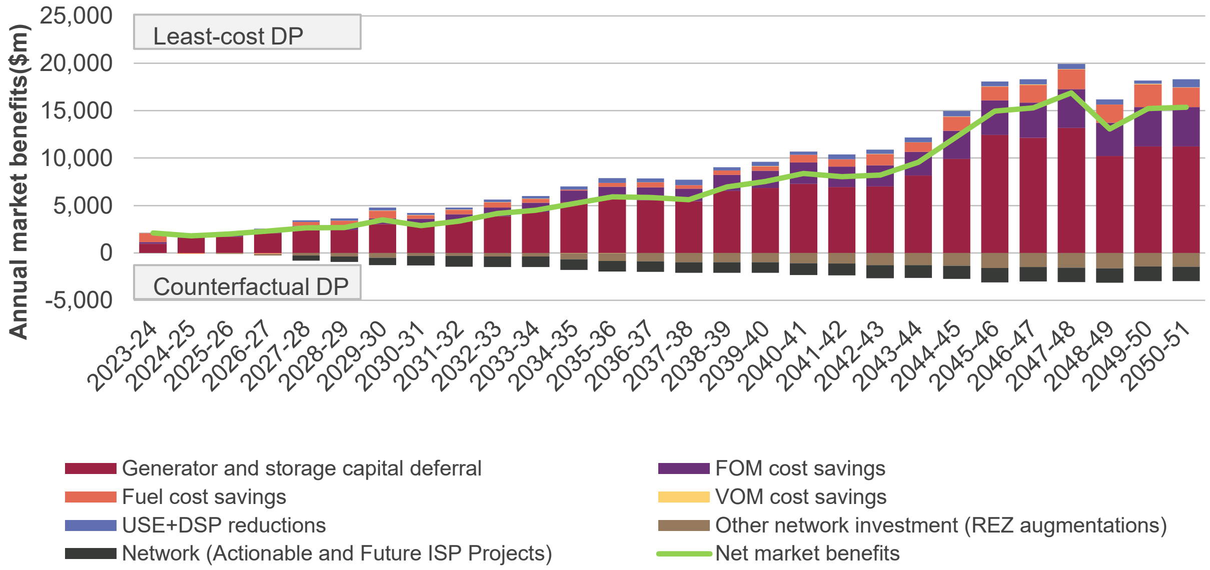
Table 11 Net market benefits by class of the least-cost development path by category, *Hydrogen Superpower* scenario

Class of market benefit	Net benefit (NPV, $ million)
Generator and storage capital deferral	60,847
FOM cost savings	16,244
Fuel cost savings	8,018
VOM cost savings	19
USE+DSP reductions	3,668
Gross market benefits	88,797
Network (Actionable and Future ISP Projects)	-10,519
Other Network investment (REZ augmentations)	-7,744
Total net market benefits	70,534

The annual net market benefits of the least-cost DP relative to the counterfactual in *Hydrogen Superpower* are shown in Figure 11. The benefits start to accrue immediately and increase over time.

The counterfactual requires additional investments in generation and storage capacity to provide firm capacity as a replacement for the ability of the interconnector augmentations to share capacity across the NEM. Most of the additional generation investments in the counterfactual are in solar, storage, offshore wind, and hydrogen gas turbines, increasing over time along with the hydrogen export demand. Offshore wind is built from the beginning of the 2030s in the Sydney, Newcastle and Wollongong zone to meet the high demand of the scenario, including for hydrogen, and emission reduction targets. Hydrogen gas turbines are also built from 2033 after all the coal fleet retires.

Figure 11 Net market benefits of the least-cost development path relative to the counterfactual in the *Hydrogen Superpower* scenario



The *Hydrogen Superpower* scenario is modelled for the first time in this Draft ISP. The development of this scenario required many assumptions to be made given the relative immaturity of grid-connected hydrogen production globally. Furthermore, the outcomes require a development of VRE that far exceeds historical levels and assume no supply chain constraints (including in relation to skilled labour, civil construction, equipment, and capital). The assumptions behind the scenario are likely to evolve over time as more information becomes available.

A6.3.4 Least-cost development path for the *Slow Change* scenario

The least-cost DP for *Slow Change* and alternative options are presented in Table 12. This scenario has the least development of ISP projects given the lowest forecast electricity consumption and absence of an explicit decarbonisation objective.

In the sample below, the alternative paths selected demonstrate:

- What is the impact in net market benefits if Sydney Ring comes early (DP1).
- Why Gladstone Grid is not developed in this scenario (DP2).
- Why VNI West and HumeLink are developed in *Slow Change* (DP3).

Table 12 Examples of development paths for *Slow Change* Scenario

ISP Project	Least-cost DP	Alternative DP1	Alternative DP2	Alternative DP3
Gladstone Grid Reinforcement	-	-	2035-26	-
Central to Southern QLD Stage 1	2040-41	2040-41	2040-41	2040-41
Central to Southern QLD Stage 2	-	-	-	-
QNI Connect	2035-36	2035-36	2035-36	2035-36
New England REZ Transmission Link	2027-28	2027-28	2027-28	2027-28
New England REZ Extension	2045-46	2045-46	2045-46	2045-46
Sydney Ring	2039-40	2028-29	2039-40	2039-40
HumeLink	2037-38	2037-38	2037-38	-
VNI West (via Kerang)	2040-41	2040-41	2040-41	-
Marinus Link (Cable 1)	2034-35	2034-35	2034-35	2034-35
Marinus Link (Cable 2)	2037-38	2037-38	2037-38	2037-38
Reduction in net market benefits ($ million)	-	-168	-139	-

The Alternative DP1 assesses the impact of developing Sydney Ring reinforcement earlier than in the least-cost DP for *Slow Change* scenario. The relative benefit of the least-cost DP compared to DP1 is shown in Table 13 below. As this scenario features some industrial load closures and therefore lower growth in consumption and peak demand, advancing the Sydney Ring augmentation does not deliver immediate benefits and therefore reduces net market benefits by $168 million.

The Alternative DP2 assesses whether it is beneficial to develop the Gladstone Grid Reinforcement in the *Slow Change* scenario. The relative benefits of Alternative DP2 shown in the table below are minor and do not cover the cost of developing an additional augmentation as the assumed reduction in industrial load in Gladstone, aligned with a closure of Gladstone Power Station eliminates any need for this augmentation in the *Slow Change* scenario.

The Alternative DP3 demonstrates the benefits of the development of VNI West and HumeLink in *Slow Change*. Even though these projects are optimal relatively late in the horizon in this scenario, they both deliver material positive net market benefits.

Table 13 Relative benefits of least-cost development path by category compared to Alternative DP1 and DP2, *Slow Change* scenario

Class of market benefit	Net benefit (NPV, $ million) relative to Alternative DP1	Net benefit (NPV, $ million) relative to Alternative DP2	Net benefit (NPV, $ million) relative to Alternative DP3
Generator and storage capital deferral	-107	0	1,169
FOM cost savings	-33	0	182
Fuel cost savings	-73	0	578
VOM cost savings	3	0	20
USE+DSP reductions	-1	0	-13
Other Network investment (REZ augmentations)	-1	0	12
Gross market benefits	-212	0	1,946
Network (Actionable and Future ISP Projects)	380	139	-1,527
Total net market benefits	168	139	420

Benefits of least-cost development path compared to counterfactual development path in the *Slow Change* Scenario

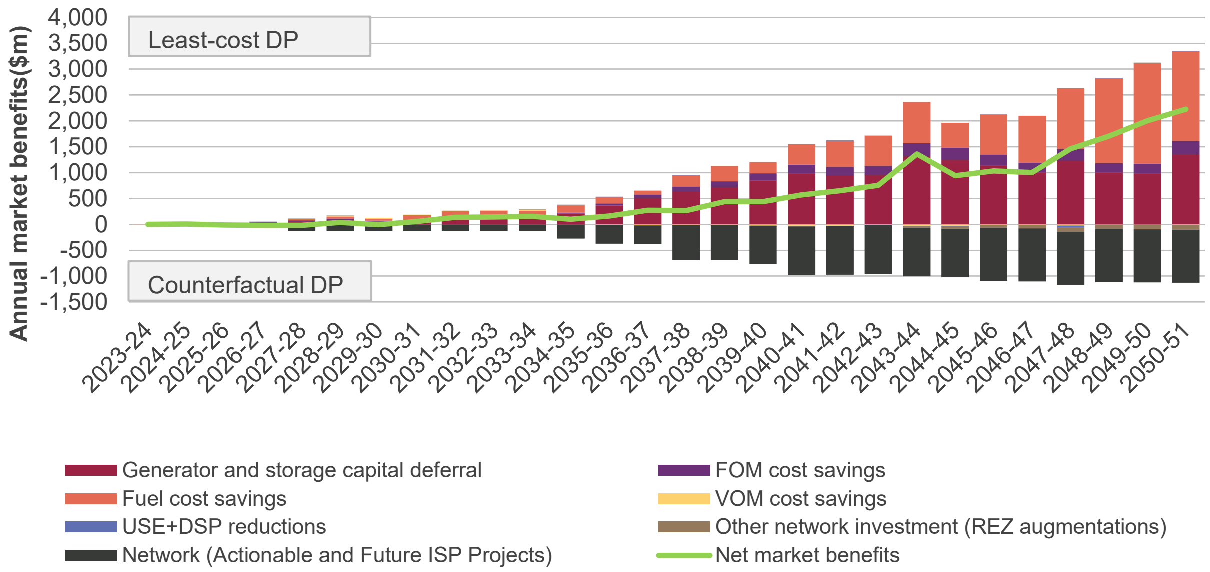
Table 14 provides a summary of the total net market benefits by class to 2050-51 of the least-cost DP, relative to the counterfactual. The cumulative gross benefits are $4.3 billion, far lower than in other scenarios. The benefits are primarily in generator capital and fuel cost savings.

Table 14 Net market benefits by class of the least-cost development path by category, *Slow Change*

Class of market benefit	Net benefit (NPV, $ million)
Generator and storage capital deferral	4,939
FOM cost savings	865
Fuel cost savings	3,395
VOM cost savings	-32
USE+DSP reductions	7
Gross market benefits	9,174
Network (Actionable and Future ISP Projects)	-4,657
Other Network investment (REZ augmentations)	-176
Total net market benefits	4,341

Figure 12 presents the annual net market benefits of the least-cost DP relative to the counterfactual in *Slow Change*. The benefits grow slowly until the late 2030s, by which time much of the coal generation fleet has retired and the least-cost DP avoids some of the investment in additional generation capacity.

Figure 12 Net market benefits of the least-cost development path relative to the counterfactual in *Slow Change*



A6.3.5 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 and coal retirements within each scenario.

There is a relatively small set of projects that are only required in the *Hydrogen Superpower* scenario, such as additional New England staged augmentations and further VNI and QNI upgrades. These projects are necessary to support supply to new electrolyser demands, facilitate substantial development in some REZs, and more generally assist in sharing renewable energy between regions.

Table 15 Comparing the least-cost DPs between scenarios

Network options	*Step Change*	*Progressive Change*	*Hydrogen Superpower*	*Slow Change*
Gladstone Grid Reinforcement	2030-31	2035-36	2028-29	-
Central to Southern QLD Stage 1	2028-29	2030-31	2028-29	2040-41
Central to Southern QLD Stage 2	2038-39	2038-39	2030-31	-
QNI Connect	2032-33	2036-37	2029-30	2035-36
QNI Connect (Stage 2)	-	-	2030-31	-
New England REZ Transmission Link	2027-28	2027-28	2027-28	2027-28
New England REZ Extension	2035-36	2038-39	2031-32	2045-46
CNSW – NNSW Option 9	-	-	2042-43	-
Sydney Ring	2027-28	2027-28	2027-28	2039-40

Network options	*Step Change*	*Progressive Change*	*Hydrogen Superpower*	*Slow Change*
Bayswater to Newcastle port augmentation	-	-	2040-41	-
HumeLink	2028-29	2035-36	2027-28	2037-38
VNI West (via Kerang)	2031-32	2038-39	2030-31	2040-41
VNI Option 6	-	-	2045-46	-
Marinus Link (Cable 1)	2027-28	2030-31	2027-28	2034-35
Marinus Link (Cable 2)	2029-30	2032-33	2029-30	2037-38

A6.3.6 Identifying potential actionable ISP projects and future ISP projects

Projects within each least-cost DP are considered to be potential actionable projects if their optimal timing is aligned with the EISD for that project (or one year later, given the two-year cycle of the ISP). The subset of potential actionable projects in these development paths are those that may require action following this ISP and form the basis of the CDPs to be assessed in the next stage of the CBA.

Given this, there are a number of projects which have been identified as being potentially actionable in at least one scenario, based on their optimal timing in a scenario's least-cost DP being at the EISD or one year later. This includes (with the EISD provided in brackets):

- VNI West (via Kerang) (2030-31).
- New England REZ Transmission Link (2027-28).
- HumeLink (2026-27).
- Sydney Ring (Reinforcing Sydney, Newcastle, and Wollongong Supply) (2027-28).
- Marinus Link (cable 1: 2027-28, cable 2: 2029-30)[7].
- Gladstone Grid Reinforcement (2027-28).

Other projects are part of the least-cost DP in at least one scenario but are not forecast to be needed at an actionable timing in any scenario and are therefore considered potential future projects. This includes:

- Central to Southern Queensland augmentations.
- Darling Downs REZ expansion.
- South East South Australia REZ expansion.
- Gladstone Grid Reinforcement.
- Far North Queensland REZ expansion.
- A project that facilitates power to Central Queensland.
- QNI Connect.
- South West Victoria REZ expansion.

[7] TasNetworks had now advised that the earliest full commissioning date for the first cable is July 2029 (750 MW, with 250 MW available in 2028) and the second cable in July 2031 (a further 750 MW, with 250 MW available in 2030), later than what has been assumed for this modelling

- New England REZ extension.
- Facilitating power out of North Queensland into Central Queensland.
- North Queensland Clean Energy Hub REZ expansion.
- An augmentation to facilitate greater transfer to supply additional electrolyser load at the Newcastle port.
- Continued augmentation of flow paths and REZs beyond 2040 – the timing and scale of these upgrades are highly uncertain and vary significantly between scenarios.

See Appendix 5 for more information on network investments.

A6.4 Determining the set of candidate development paths to assess the Draft ODP

A CDP represents a collection of DPs which share a set of potential actionable projects. CDPs therefore vary with respect to status of the potential actionable projects. CDPs also include consideration of proceeding with early works, a form of project staging which refers to all the critical path investments that are needed to ensure a project can be delivered by its earliest planned delivery time, but does not include actual implementation. They are sometimes known as making the project ‘shovel ready’.

The least-cost DP in each scenario has been used as the basis for forming the set of CDPs which are considered throughout this section. The additional CDPs considered are based on the process set out in Section 5.4 of the ISP Methodology. At a high level this includes forming new CDPs by:

- Removing potential actionable projects from CDPs.
- Adding additional projects, or alternatives to projects that already feature in CDPs.
- Staging potential actionable project through the use of early works to test option value as a means of minimising risks to consumers.

The set of CDPs considered is shown in Table 16, which also sets out how the CDP has been developed. The purpose of each CDP will be further expanded in Section A6.5, but in brief are as follows:

- **Least-cost DPs for the four scenarios:**
  - CDP1: Based on *Progressive Change* least-cost DP.
  - CDP2: Based on *Step Change* least-cost DP.
  - CDP3: Based on *Hydrogen Superpower* least-cost DP.
  - CDP4: Based on *Slow Change* least-cost DP.
- **Variations to test timing of project delivery and/or event-driven scenarios:**
  - CDP5 is based on the *Progressive Change* least-cost DP (CDP1) but with Marinus Link actionable.
  - CDP6 is also based on the *Progressive Change* least-cost DP (CDP1) but with VNI West Link actionable. CDP5 and CDP6 effectively bridge the difference between CDP1 and CDP2.
  - CDP8 adds HumeLink as an actionable project to the *Step Change* least-cost DP (CDP2).
  - CDP13 removed Marinus Link as an option from CDP12, such that it is never delivered.
- **Testing slower investments:**
  - CDP7 removes the New England REZ Transmission Link augmentation as an actionable project from the *Progressive Change* least-code development path (CDP1) and provides an ability to explore the merits of the project through comparison with CDP1.
  - CDP9 removes all actionable projects entirely.
- **Testing staged projects with early works:**
  - CDP10 is based on CDP5, but with a staged delivery of VNI West with early works as the first stage. This CDP therefore allows consideration of the value of staging VNI West compared to no action on the

project (through comparison with CDP5) and with progressing with the full project without staging (CDP2).

- CDP11 adds HumeLink as an actionable project to CDP10, providing the ability to understand the costs and benefits of an actionable HumeLink timing through comparison with CDP10.
- CDP12 adds HumeLink as a staged actionable project to CDP10. This therefore allows an assessment of the value of a staged HumeLink delivery through comparison with CDP10 and CDP11.

Table 16 Candidate development paths

CDP Number	Purpose	New England REZ Transmission Link	Sydney Ring	Marinus Link	VNI West	HumeLink	Gladstone Grid Reinforcement
1	*Progressive Change* least-cost	Potential actionable	Potential actionable				
2	*Step Change* least-cost (*Progressive Change* with ML and VNI West)	Potential actionable	Potential actionable	Potential actionable	Potential actionable		
3	*Hydrogen Superpower* least-cost (all actionable)	Potential actionable	Potential actionable	Potential actionable	Potential actionable	Potential actionable	Potential actionable
4	*Slow Change* least-cost (*Progressive Change* without Sydney Ring actionable)	Potential actionable					
5	*Progressive Change*, with Marinus Link actionable	Potential actionable	Potential actionable	Potential actionable			
6	*Progressive Change*, with full VNI West actionable	Potential actionable	Potential actionable		Potential actionable		
7	*Progressive Change*, without New England REZ Transmission Link actionable		Potential actionable				
8	*Step Change*, with HumeLink actionable	Potential actionable	Potential actionable	Potential actionable	Potential actionable	Potential actionable	
9	No actionable projects						
10	CDP5, with VNI West staged	Potential actionable	Potential actionable	Potential actionable	Stage 1 (Early Works)		
11	CDP10, with HumeLink actionable	Potential actionable	Potential actionable	Potential actionable	Stage 1 (Early Works)	Potential actionable	
12	CDP10, with HumeLink staged	Potential actionable	Potential actionable	Potential actionable	Stage 1 (Early Works)	Stage 1 (Early Works)	
13	CDP12, but with Marinus Link not available	Potential actionable	Potential actionable	Never available	Stage 1 (Early Works)	Stage 1 (Early Works)	

A6.5 Assessing the candidate development paths

A6.5.1 Ranking the Candidate Development Paths

The determination of a Draft ODP is informed by assessing the performance of the CDPs across the scenarios, as well as their robustness demonstrated by sensitivity analysis (see Section A6.6.5). This section compares the various CDPs to explore the benefits and costs provided by the potential actionable projects, including their impact on each other.

The ISP Methodology outlined two approaches that are used to rank the CDPs by considering outcomes across the scenarios:

- Approach A: a scenario-weighted approach that calculates the average net market benefits of each CDP by applying the scenario weightings to the market benefits within each scenario. CDPs are ranked in descending order according to these weighted net market benefits.
- Approach B: a 'least-worst weighted regrets' (LWWR) approach which calculates the 'regret'[8] of each CDP in each scenario, weights that regret by the scenario weighting and determines the maximum 'weighted regret' across the scenarios. CDPs are ranked in ascending order according to this maximum (worst) weighted regret.

Table 17 shows the performance of each CDP in each scenario, as well as the weighted net market benefits, the worst weighted regret, and the rankings under each approach.

Table 17 Performance of candidate development paths across scenarios (in $ billion) – ranked in order of weighted net market benefits

CDP Number	*Step Change*	*Progressive Change*	*Hydrogen Superpower*	*Slow Change*	Weighted Net Market Benefits (NMB)	WNMB Rank	Worst Weighted Regret	LWWR Rank
10	25.59	16.35	70.01	3.52	29.58	1	0.11	1
12	25.59	16.20	70.20	3.35	29.56	2	0.15	3
2	25.59	16.26	70.01	3.25	29.54	3	0.13	2
5	25.51	16.51	69.60	3.71	29.52	4	0.16	4
6	25.59	16.47	69.37	3.62	29.51	5	0.20	5
1	25.50	16.72	68.95	4.17	29.49	6	0.27	6
7	25.49	16.67	68.45	3.94	29.37	7	0.35	10
4	25.41	16.50	68.73	4.34	29.35	8	0.31	8
11	25.39	15.66	70.20	3.13	29.30	9	0.31	7
8	25.39	15.56	70.20	2.87	29.26	10	0.34	9
3	25.34	15.47	70.53	2.51	29.25	11	0.36	11
9	25.28	16.36	68.33	4.05	29.16	12	0.38	12
13	20.96	13.54	64.50	2.19	25.46	13	2.32	13

[8] 'Regret' represents the difference between the net market benefits of a CDP in a scenario compared to the market benefits of the least-cost DP in that scenario. This regret represents the cost of taking the different decisions reflected in that CDP compared to the optimal approach given perfect foresight.

Table 17 highlights that the top-ranked CDPs all deliver over $29 billion NPV of net market benefits when weighted across the four scenarios. The net market benefits presented in this table do not include any additional competition and reliability benefits calculated through detailed time-sequential modelling to compare specific CDPs. Those benefits are documented when relevant to a specific CDP comparison (notably in Section A6.6.2 and A6.6.3)

The remainder of this section explores the value provided by those key projects that feature at an actionable timing in highly ranked[9] CDPs. Section A6.6 details more specific comparisons between CDPs and their relevance to how AEMO has determined the ODP. Where relevant, these comparisons also incorporate insights from sensitivity analysis, option value, as well as any additional reliability benefits calculated using more detailed times-sequential modelling. Section A6.6.5 then provides an assessment of the robustness of the high ranking CDPs to sensitivity analysis.

A6.5.2 Assessing the critical projects in high ranking CDPs

The higher ranked CDPs (see Table 17) feature the following key network projects as potentially actionable projects, some with staging:

- New England REZ Transmission Link (contributing roughly $5.5 billion of the $26 billion NMB in *Step Change*).
- Sydney Ring (contributing roughly $3.4 billion of the $26 billion NMB in *Step Change*).
- Marinus Link (contributing roughly $4.6 billion of the $26 billion NMB in *Step Change*).
- VNI West (contributing roughly $1.9 billion of the $26 billion NMB in *Step Change*).
- HumeLink (contributing roughly $1.3 billion of the $26 billion NMB in *Step Change*).

All these projects feature at some stage within each scenario's least-cost DP, but for some projects with significant differences in the optimal timing. In the most likely *Step Change* scenario, the least-cost DP has all of these key projects operational by 2031-32 (see Table 2). The remainder of this section illustrates the significant benefits provided by these projects; Section A6.6 focuses on determining the timing that optimises benefits to consumers, taking into consideration regret costs associated with over- or under-investment across scenarios.

New England REZ transmission Link

With the annual VRE generation targets of the 2021 IIO Report[10] development pathway included in all scenarios, the network augmentation to provide greater access to the New England REZ is of critical importance to ensure this generation can be delivered efficiently to benefit all consumers. This is demonstrated by the network augmentation featuring in each scenario's least-cost DP within an actionable timeframe.

Table 18 shows the market benefits delivered by the project compared to a DP that removes New England augmentations entirely (referred to as a "TOOT", [Take-one-out-at-a-time]), which clearly demonstrates that increasing the access to the New England REZ is critical to efficient transformation of the NEM, contributing

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[9] When referring to "higher" ranked CDPs, throughout this Appendix this is taken to mean a lower number – with rank 1 being the highest ranked CDP. This means the CDP with the highest weighted net market benefits, or the lowest worst weighted regret depending on the rank.

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

approximately $5.5 billion towards the $26 billion total net market benefits of the highest ranked CDP in *Step Change*.

Table 18 Net market benefits of New England augmentations, *Step Change*

Class of market benefit	Net benefit (NPV, $ million) of New England augmentation
Generator and storage capital deferral	4,399
FOM cost savings	917
Fuel cost savings	387
VOM cost savings	-21
USE+DSP reductions	474
Other Network investment (REZ augmentations)	1,055
Gross market benefits	7,212
Network (Actionable and Future ISP Projects)	-1,677
Total net market benefits	5,535

The key drivers of the benefits are as follows:

- Initially associated with more effective development of VRE in New South Wales. In particular, the access to high-quality VRE in the New England REZ provides both generator capital cost and fuel cost savings.
- As time goes on, the benefits of co-optimised renewable generation and transmission development increase, with the greater diversity provided by the development of the New England REZ and associated transmission also providing benefits through reduced need for additional firming generation.
- Furthermore, the total VRE investment required is much higher without the New England augmentations, due to development of lower quality VRE, but also because the augmentations are utilised to increase resource sharing between Queensland and New South Wales once QNI Connect is delivered in the early 2030s.
- Without the New England augmentations, further network augmentation to unlock other REZs is required, particularly in New South Wales.

Sydney Ring (Reinforcing Sydney, Newcastle, and Wollongong Supply)

The Sydney Ring augmentation increases the transfer capability into the Sydney, Newcastle, and Wollongong area. The primary driver of the augmentation is the retirement of coal generators located within this area, as well as to efficiently service increasing peak demand.

The key sources of market benefits for the Sydney Ring are a reduction in capital costs due to avoided development of peaking generation within the Sydney, Newcastle and Wollongong area, as well as a reduction in fuel costs associated with operating additional gas generation in the same area.

Compared to if the project was never developed, there are substantial relative market benefits which grow throughout the modelling horizon. Limitations transferring power to Sydney result in more expensive generation developments, including offshore wind towards the end of the horizon. Figure 13 shows the annual relative benefits of having the Sydney Ring based on a comparison with a TOOT in the *Step Change* scenario, and Table 19 summarises the total net market benefits provided by Sydney Ring, highlighting that the project contributes approximately $3.4 billion towards the $26 billion total net market benefits of the highest ranked CDP in *Step Change*

Figure 13 Example of the relative market benefits of the Sydney Ring augmentation, *Step Change* scenario

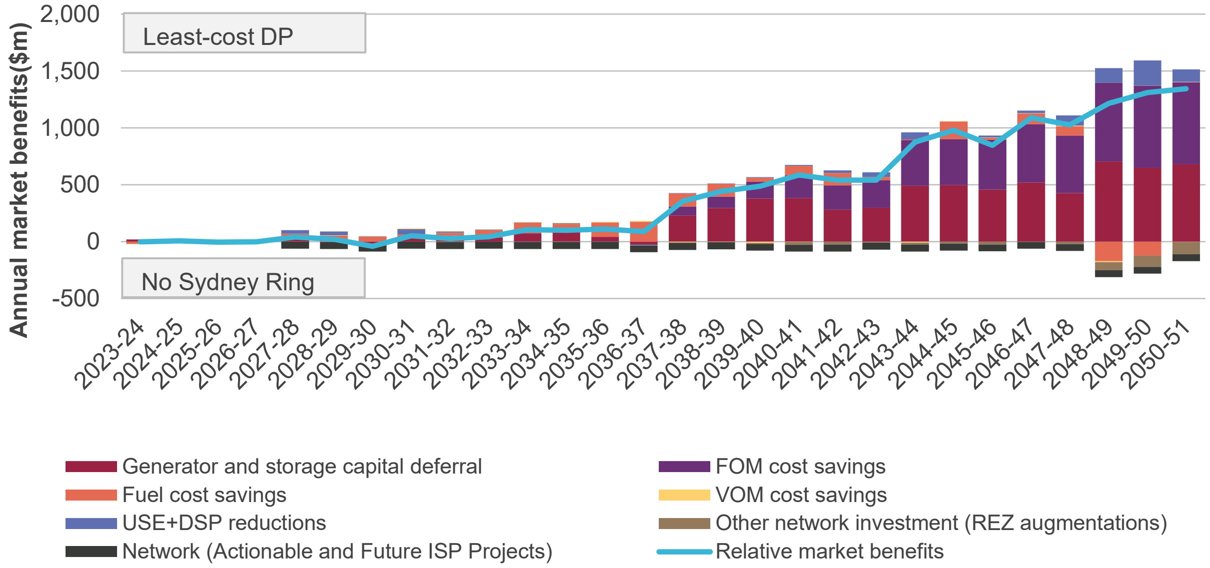


Table 19 Relative market benefits of Sydney Ring augmentation ($ billion)

Class of market benefit	Relative benefit (NPV, $ million) of Sydney Ring augmentation
Generator and storage capital deferral	1,888
FOM cost savings	1,389
Fuel cost savings	548
VOM cost savings	2
USE+DSP reductions	239
Other Network investment (REZ augmentations)	-92
Gross market benefits	3,974
Network (Actionable and Future ISP Projects)	-580
Total net market benefits	3,394

Marinus Link

The main driver of benefits provided by Marinus Link is in allowing for increased development and export of Tasmania's strong wind resources, including developments required to meet the TRET. With higher capacity factors for wind generation in Tasmania compared to mainland REZs, developing Marinus Link enables greater access to this quality resource, helping reduce the scale of VRE development needed in other regions and increase the diversity of wind resources across the NEM. Furthermore, the flexibility provided by existing hydro resources and new pumped hydro generation in Tasmania adds further value.

Table 20 shows the market benefits of Marinus Link by comparing CDP12 (with actionable New England REZ Transmission Link, Sydney Ring, and Marinus Link augmentations, and staged HumeLink and VNI West augmentations) with CDP13 (as CDP12 but with no Marinus Link augmentation constructed throughout the modelling horizon).

Marinus Link delivers significant benefits across the scenarios, ranging from $1.17 billion in the *Slow Change* to $5.7 billion in *Hydrogen Superpower*.

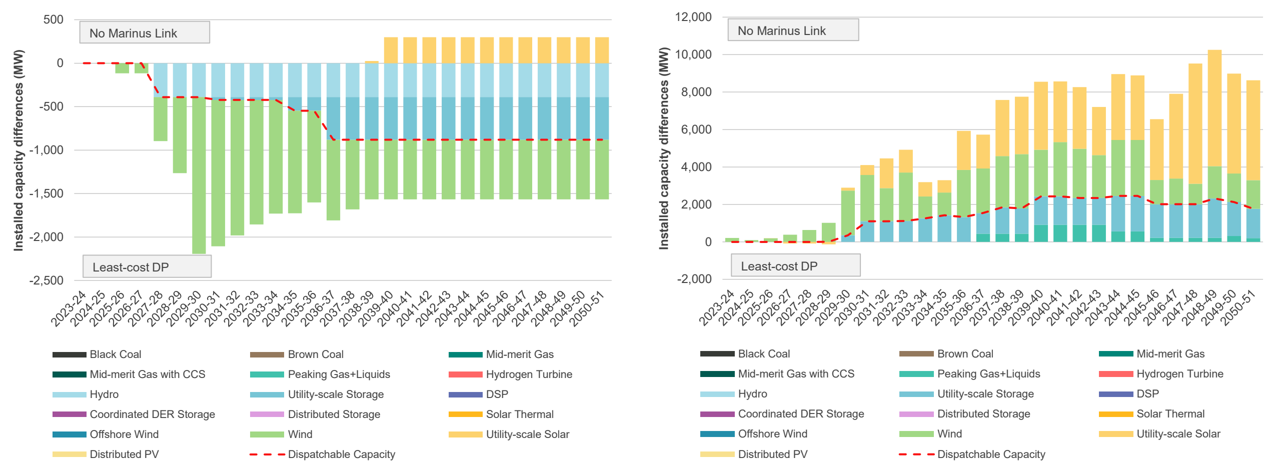
The benefits of Marinus Link are primarily accrued through savings in capital costs. Major savings in fuel and REZ augmentation costs are also provided as generation from other sources and REZs is deferred, and curtailment of Tasmanian wind is reduced.

Table 20 Market benefits provided by Marinus Link, *Step Change* scenario

CDP Number	*Step Change*	*Progressive Change*	*Hydrogen Superpower*	*Slow Change*	Weighted Net Market Benefits	WNMB Rank	Worst Weighted Regret	LWWR Rank
12	25.59	16.20	70.20	3.35	29.56	2	0.15	3
13	20.96	13.54	64.50	2.19	25.46	13	2.32	13
Benefit of Marinus Link	4.63	2.66	5.70	1.17	4.10			

Figure 14 compares generation developments in *Step Change* against a DP without either cable of Marinus Link. With the augmentations in place, there is greater wind and pumped hydro development and additional flexible hydro capacity unlocked in Tasmania. It also allows for greater export and reduced curtailment of generation developed as a result of the TRET. This additional generation capacity in Tasmania helps reduce the scale of VRE and firming investments in peaking gas and storage that would otherwise be needed on the mainland. Even without TRET though, these cables still deliver sizeable net market benefits (see 'other considerations' later in this section).

Figure 14 Comparison of generation capacity with and without Marinus Link in Tasmania (left) and on the mainland (right), *Step Change* scenario



Focusing on *Step Change*, Table 21 reinforces the significant capital cost savings that Marinus Link delivers, both in reducing investment in lower quality VRE and firming capacity, but also further REZ augmentation. It highlights that the project (both cables) contributes approximately $4.6 billion towards the $26 billion total net market benefits of the highest ranked CDP in *Step Change*.

Table 21 Net market benefits of Marinus Link

Class of market benefit	Net benefit (NPV, $ million) of Marinus Link
Generator and storage capital deferral	4,152
FOM cost savings	650
Fuel cost savings	723
VOM cost savings	-99
USE+DSP reductions	330
Other Network investment (REZ augmentations)	716
Gross market benefits	6,472
Network (Actionable and Future ISP Projects)	-1,838
Total net market benefits	4,634

Prompt delivery of a second Marinus Link cable delivers benefits in all scenarios

As shown in Table 22, the least-cost DP of all scenarios results in the development of both Marinus Link cables at some stage. In all scenarios, the second cable is built two years after the first, except the *Slow Change* scenario which delays the second cable an additional year. When Marinus Link is brought forward as an actionable project, the second cable is sometimes shifted to three years after the first cable in the *Progressive Change* scenario, depending on the individual CDPs.

Table 22 Comparing Marinus Link optimal timing between scenarios

ISP Project	*Step Change*	*Progressive Change*	*Hydrogen Superpower*	*Slow Change*
Marinus Link (Cable 1)	2027-28	2030-31	2027-28	2034-35
Marinus Link (Cable 2)	2029-30	2032-33	2029-30	2037-38

A comparison of CDP5 with and without the second Marinus Link cable demonstrates the costs and benefits of proceeding with prompt delivery of the second Marinus Link cable after the first cable.

0 shows that the second Marinus Link cable delivers net market benefits in all four scenarios. The benefits of second Marinus cable vary between scenarios, as they are influenced by decarbonisation targets and the associated speed of thermal generation retirements, mainly in Victoria.

Although the second cable does not necessarily deliver benefits immediately after its construction, the additional $600m cost of delivering the second cable more than three years after the first mean that the timely delivery of the second cable is always beneficial.

Table 23 Determining the benefits of a second Marinus Link cable ($ billion)

Scenario	CDP5	CDP5 with no second Marinus Link cable	Benefit of second Marinus Link cable
Step Change	25.51	23.83	1.68
Progressive Change	16.51	15.76	0.75
Hydrogen Superpower	69.60	67.62	1.97
Slow Change	3.71	3.03	0.68
Weighted Net Market Benefits	29.52	28.10	1.42

Other considerations

The TRET is a legislated policy that targets 150% renewable energy by 2030 and 200% by 2040. As a legislated policy, the TRET has been included in all scenarios. AEMO has conducted additional sensitivities to explore the impact of the TRET on the benefits provided by Marinus Link (based on CDP2). Table 24 shows the total net market benefits provided by Marinus Link over the modelling horizon. The net market benefits presented in this table include comparisons where:

- The TRET is included both with and without Marinus Link.
- The TRET is included when Marinus Link is in place but removed when it is not.
- The TRET is removed both with and without Marinus Link.

Table 24 Impact of the TRET on Marinus Link benefits ($ billion)

Scenario	*Step Change*	*Progressive Change*
Benefits of ML (with TRET)	4.63	2.54
Benefits of ML (if no TRET without ML)	3.37	1.13
Benefits of ML (if no TRET)	3.34	1.34

Even considering the removal of the TRET, Marinus Link clearly delivers net market benefits. However, the inclusion of the TRET adds over $1 billion to the net market benefits in both the *Step Change* and *Progressive Change* scenarios. Furthermore, without the TRET, the optimal timing of Marinus Link would likely be delayed by up to three years in the *Progressive Change* scenario.

VNI West

The primary driver of value for VNI West is early coal retirements in Victoria. This is evident in the earlier optimal timing for the project in the scenarios with more rapid emission reductions. Earlier coal retirements create a need for additional firming capacity in Victoria, as well as being a driver for new VRE investment.

Figure 15 shows the annual classes of market benefit provided by VNI West at its optimal timing in the *Step Change* scenario compared to a TOOT (where VNI West is not constructed). The largest component of the market benefits are the avoided generator capital costs that largely arise due to a reduced need for new firming generation in Victoria and South Australia (as shown in Figure 16), though additional firming capacity is still required even with VNI West.

Figure 15 Relative market benefits of VNI West in *Step Change*

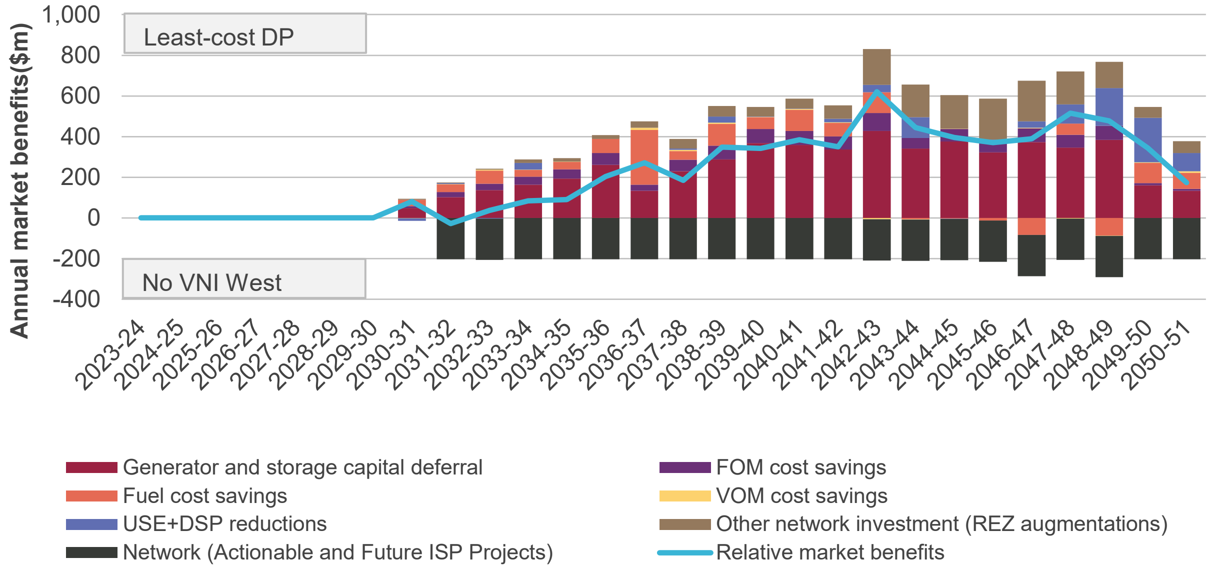
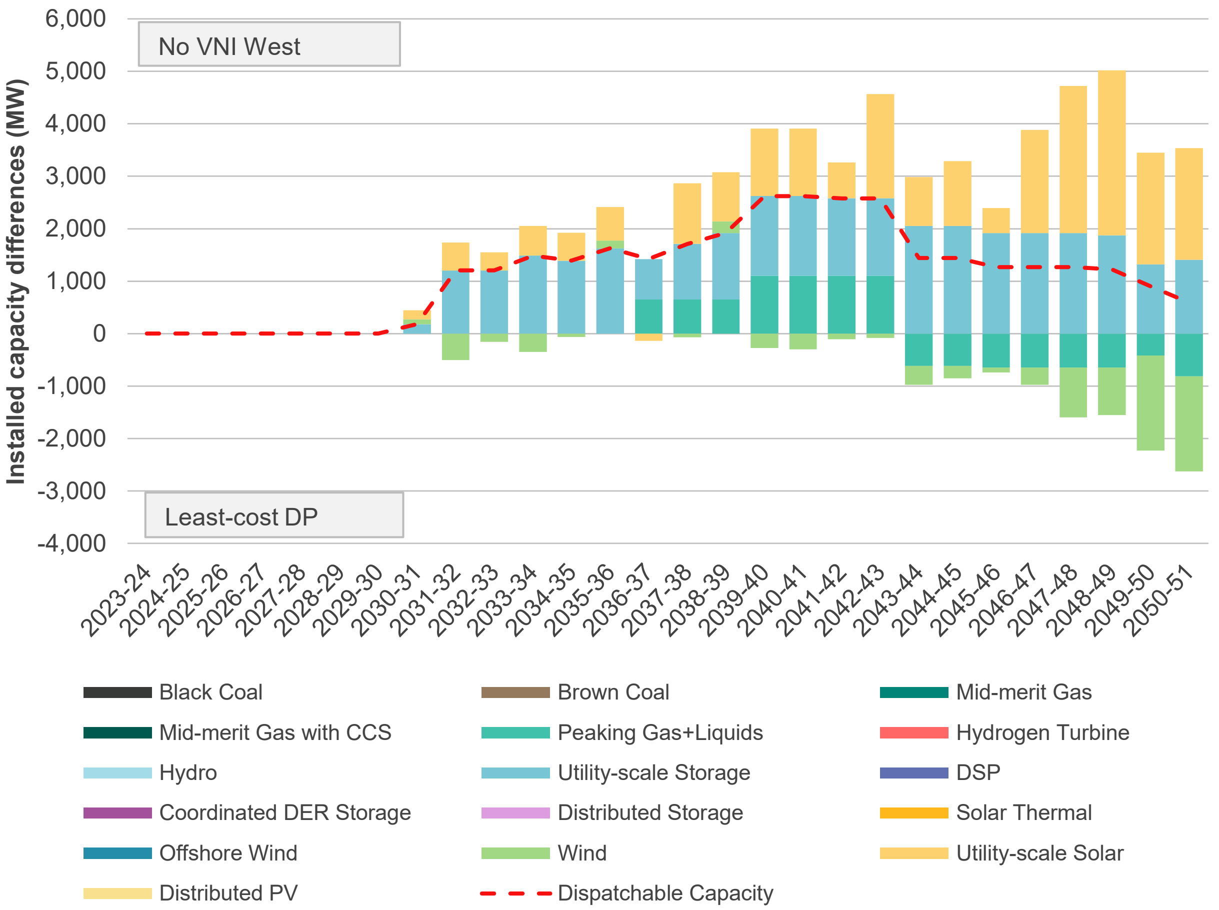


Figure 16 Differences in generation and storage capacity built with and without VNI West – *Step Change* scenario

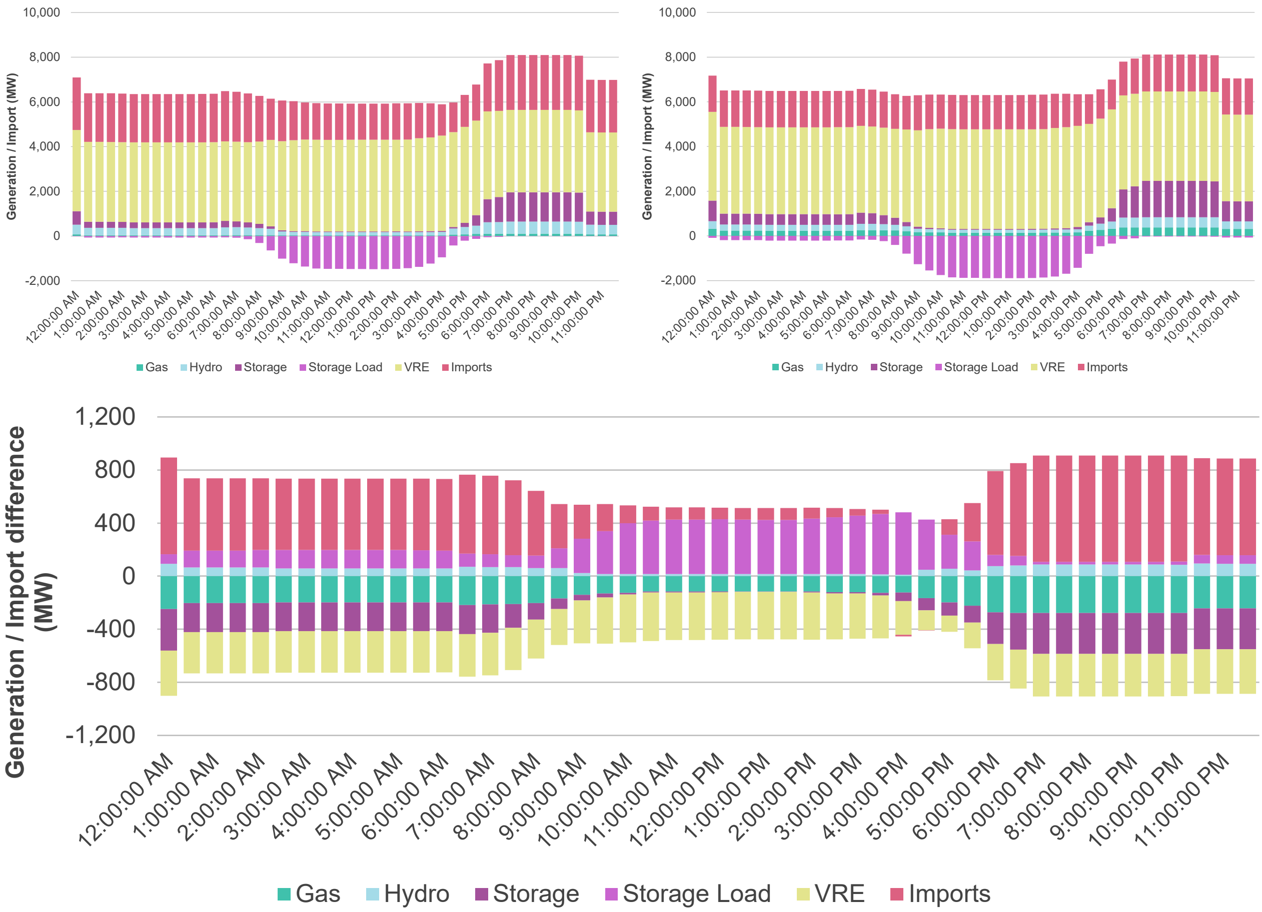


Additional cost savings arise due to reductions in REZ augmentation costs, as VNI West provides additional capacity for the Murray River and Western Victoria REZs. Without VNI West, some additional augmentations to these REZs, as well as others in the NEM, are required.

Further cost savings are attributable to the reduction in VRE curtailment, both due to increased transfers between Victoria and New South Wales and due to the additional REZ transmission capacity in Victoria. Without VNI West, this higher curtailment means that more VRE capacity is required to effectively produce the same amount of energy.

Finally, VNI West results in some fuel cost savings, primarily due to reductions in gas generation in Victoria in favour of lower cost generation in other regions, as observed in Figure 17. The impact of lower gas prices on VNI West is explored in Section A6.7.1.

Figure 17 Average generation and imports in Victoria by time-of-day in 2036-37 with VNI West (left) and without VNI West (right), and the difference (with minus without VNI West, below), *Step Change* scenario



The net market benefits of VNI West in *Step Change* are summarised in Table 25, which highlights that VNI West contributes approximately $1.9 billion towards the $26 billion of net market benefits in the highest ranked CDP in *Step Change.*

Table 25 Net market benefits of VNI West

Class of market benefit	Net benefit (NPV, $ million) of VNI West
Generator and storage capital deferral	1,812
FOM cost savings	358
Fuel cost savings	424
VOM cost savings	16
USE+DSP reductions	211
Other Network investment (REZ augmentations)	480
Gross market benefits	3,300
Network (Actionable and Future ISP Projects)	-1,421
Total net market benefits	1,879

HumeLink

The optimal timing of HumeLink is closely linked to coal retirements in New South Wales. Although coal retirements are accelerated in the *Progressive Change* scenario, these are at least partially offset by new committed and anticipated peaking generation and the impact of the requirement for 2 GW of storage capable of being able to generate continuously for at least eight hours, to be developed in New South Wales before 2030.

In general, HumeLink delivers positive net market benefits from the time at which the fourth New South Wales coal-fired power station (including Liddell) retires. Over this period, HumeLink provides greater access to Snowy 2.0, which reduces the need for additional utility-scale storage. In the early years of the horizon, HumeLink also helps to manage VRE variability and result in more investment in lower cost solar in favour of more expensive wind generation.

In the long term, HumeLink reduces the investment in VRE required due to the ability to utilise Snowy 2.0 more effectively to avoid generation curtailment, as well as providing greater access to REZs in southern New South Wales and more transfer capability between New South Wales and southern states.

These benefits are evident in Figure 18, which compares the capacity in the *Step Change* scenario in a case with HumeLink at an actionable timing compared to a case without HumeLink at any stage.

In the early years, HumeLink also provides avoided fuel cost savings, primarily through avoided gas generation. The benefits provided by HumeLink in *Step Change* are summarised in Table 26, highlighting that HumeLink contributes approximately $1.3 billion towards the $26 billion of net market benefits in the highest CDP

Figure 18 Comparison of capacity with HumeLink (in 2026-27) and without HumeLink, *Step Change* scenario

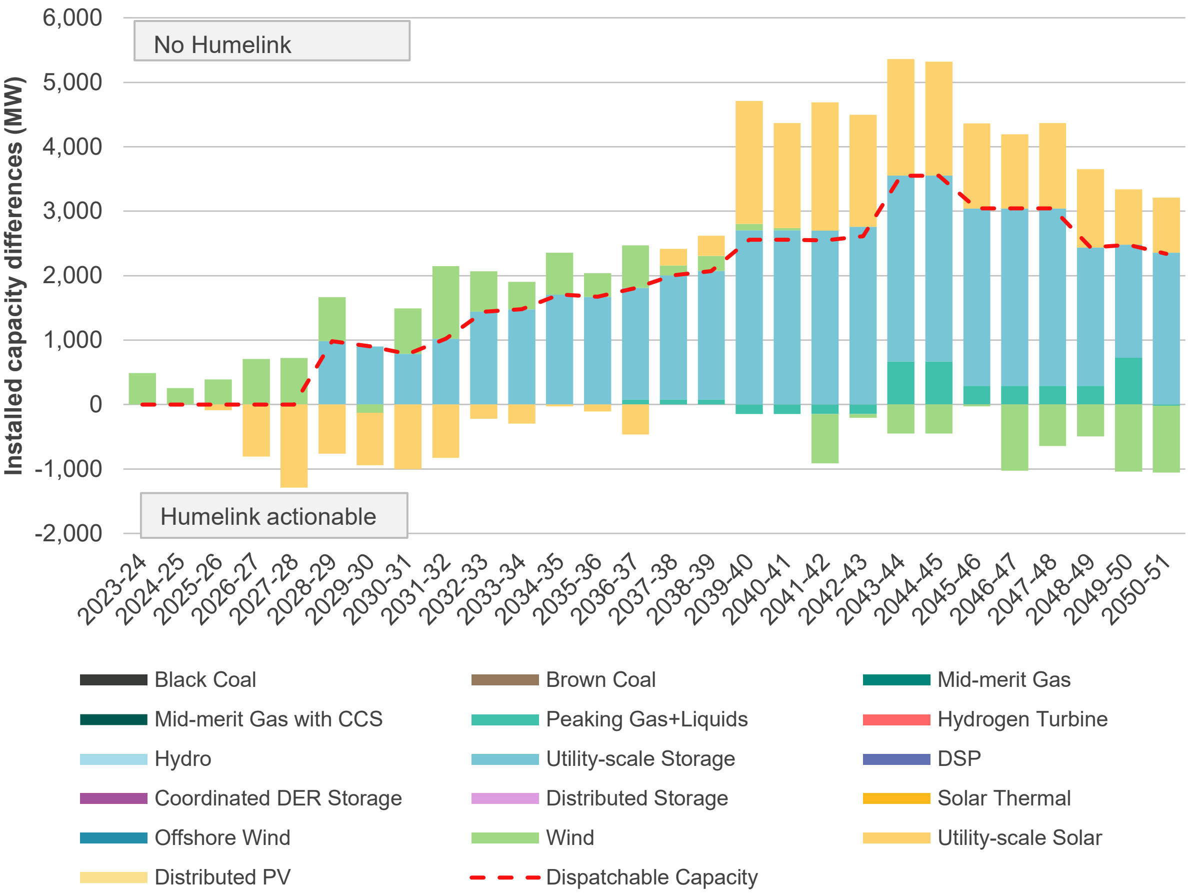


Table 26 Net market benefits of HumeLink in *Step Change*

Class of market benefit	Net benefit (NPV, $ million) of HumeLink
Generator and storage capital deferral	2,485
FOM cost savings	323
Fuel cost savings	319
VOM cost savings	20
USE+DSP reductions	84
Other Network investment (REZ augmentations)	100
Gross market benefits	3,330
Network (Actionable and Future ISP Projects)	-2,026
Total net market benefits	1,303

The clear link between New South Wales coal retirements and HumeLink is further illustrated by a sensitivity on the *Progressive Change* scenario that assumes that the fourth New South Wales coal station is retired by 2027-28. The results provided in Table 27 show that under this assumption, the benefits provided by having HumeLink built as early as possible compared to 2035-36 (the original optimal timing in the *Progressive Change* scenario) change from being negative to positive. This clearly demonstrates the resilience to accelerated coal retirements provided by HumeLink.

Table 27 Net market benefits of an actionable HumeLink with early black coal retirement (CDP8 vs CDP2)

CDP Number	Net market benefits of actionable VNI West ($ million) vs *Progressive Change* Optimal timing
Progressive Change **retirements**	-700
Four NSW coal retirements by 2027-28	464

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

Table 28 presents a comparison of the weighted net market benefits in all scenarios for CDP10 compared with CDP9, which has no actionable projects, and also with a collection of DPs that exclude all new interconnector augmentations (specifically VNI West, Marinus Link and QNI Connect) entirely.

Table 28 Determining the benefits of a coordinated approach to transmission development ($ billion)

CDP Number	*Step Change*	*Progressive Change*	*Hydrogen Superpower*	*Slow Change*	Weighted Net Market Benefits
12: Draft Optimal development path	25.59	16.20	70.20	3.35	29.56
9: No actionable projects	25.28	16.36	68.33	4.05	29.16
No Interconnectors (VNI West, Marinus Link, QNI Connect)	17.10	12.09	42.32	2.34	19.35
Proportion of the benefits of the Draft ODP attributable to interconnectors	33%	25%	40%	30%	35%

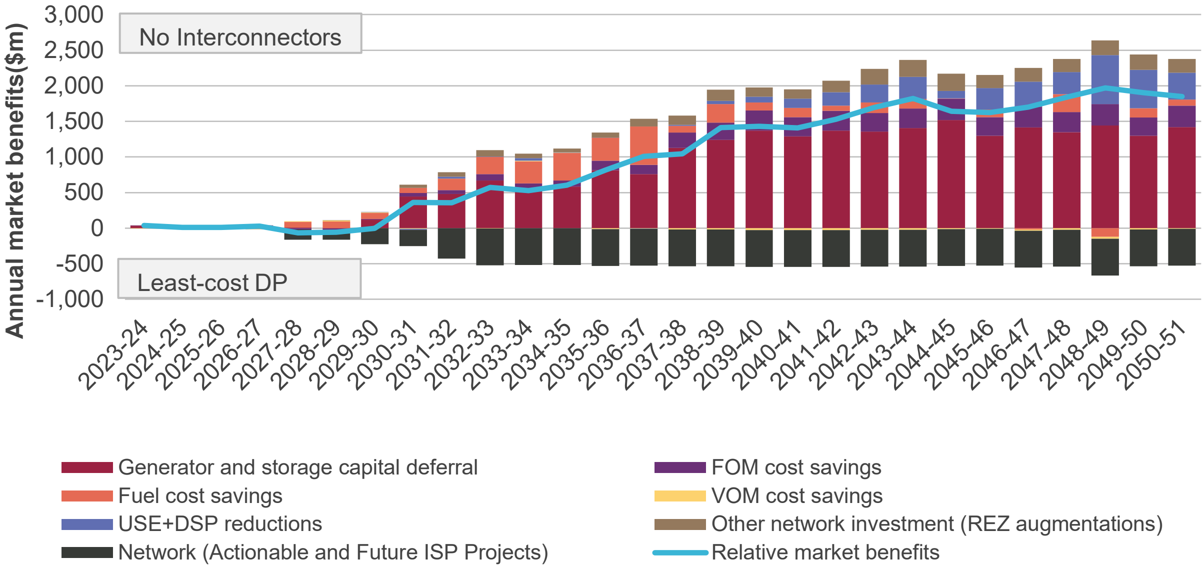
Based on these outcomes, it is evident that:

- Delaying progress on all ISP projects will result in a decrease of over $400 million in weighted net market benefits.
- Augmenting the interconnectors between regions delivers between 25% and 40% of total net market benefits, but the majority of benefits arise from developing transmission within regions to unlock REZ.

Figure 19 below highlights the need for transmission investment, comparing the outcomes of CDP10 against the DP without VNI West, Marinus Link and QNI Connect at any stage, for the *Step Change* scenario. Without the aforementioned interconnector augmentations, there is a need for significant capital expenditure in all regions in the NEM due to greater reliance on local generation. This also results in higher curtailment of VRE in general and higher fuel costs.

The total value provided by the interconnectors in *Step Change* ($8.49 billion – the difference between CDP12 and the No Interconnectors case) is roughly equivalent to the sum of the TOOTs presented in Section A6.5.2 ($4.6 billion for Marinus Link and $1.9 billion for VNI West) and QNI Connect ($1.3 billion, see Section A6.7.5), which totals $7.8 billion.

Figure 19 Demonstrating the market benefits of interconnector augmentations



A6.6 Exploring the risks and benefits of actionable project timings

While all projects discussed above deliver significant benefits to consumers, for some, the optimal timing varies considerably across scenarios. Therefore, analysis was needed to assess the benefits of progressing now as an actionable project following the final 2022 ISP versus taking a "wait and see" approach, and not progressing with the project until at the least the 2024 ISP. This analysis effectively assessed the risk of under- and over-investment in each scenario with and without the project being actionable in this Draft ISP and determined the change in scenario-weighted net market benefits.

New England REZ Transmission Link

The regrets associated with delaying the New England REZ Transmission Link augmentation beyond its actionable timing are best demonstrated through a comparison between CDP7 and CDP1. These CDPs are equivalent with the exception that CDP7 does not proceed with the New England development at the earliest timing (2027-28) and instead pushes this development two years later in all scenarios.

A comparison of net market benefits between the two CDPs is shown in Table 29.

Table 29 Comparing net market benefits in CDP1 and CDP7 ($ billion) – New England REZ Transmission Link

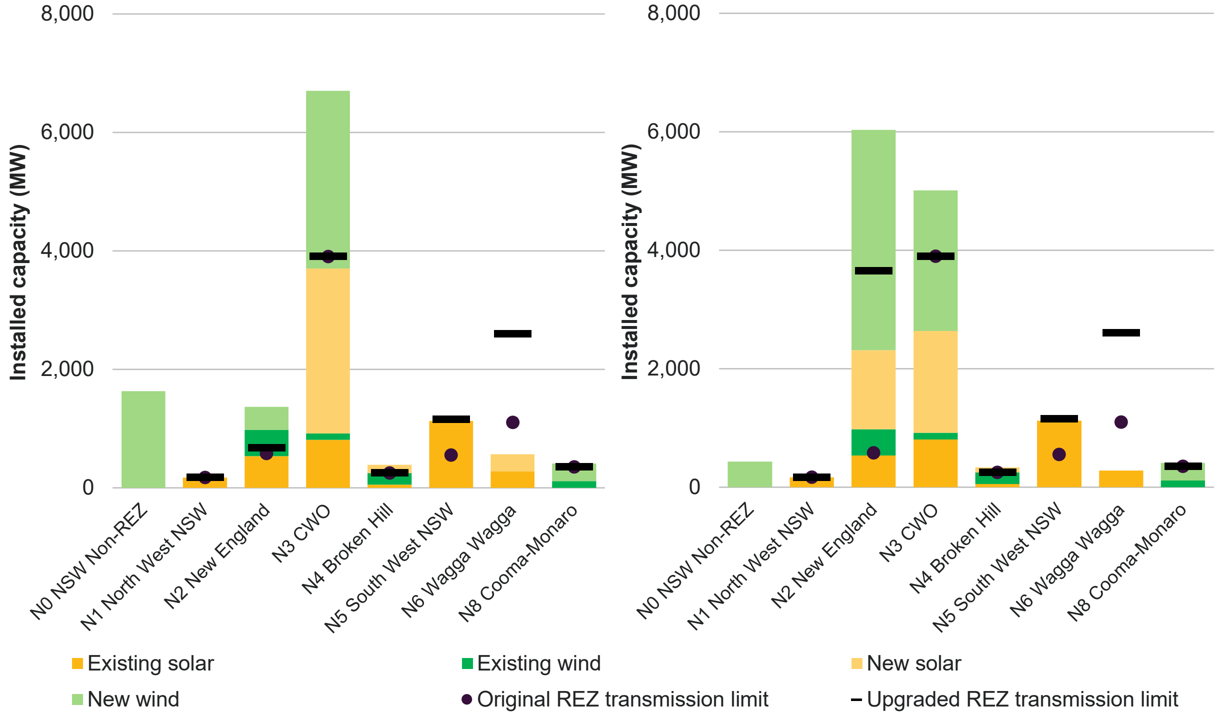
Scenario	CDP1 – with New England REZ Transmission Link actionable	CDP7 – without New England REZ Transmission Link actionable	Regret of "waiting and seeing", rather than acting now
Step Change	25.50	25.49	0.01
Progressive Change	16.72	16.67	0.04
Hydrogen Superpower	68.95	68.45	0.49
Slow Change	4.17	3.94	0.24
Weighted Net Market Benefits	29.49	29.37	0.11

In all scenarios, the additional regret of delaying New England REZ Transmission Link beyond its earliest timing is relatively minor. However, in all scenarios, even if not progressed immediately, the optimal timing remains before 2030. The primary costs of under-investment relate to the less effective distribution of VRE development in New South Wales to meet the objectives of the Electricity Infrastructure Roadmap.

Figure 20 compares the development of VRE in New South Wales between the two CDPs by 2028-29 in the *Step Change* scenario. This shows that without the New England REZ Transmission Link augmentation, there is a substantial overbuild of capacity in the Central West Orana REZ and the New South Wales Non-REZ[11], which is located in a similar geographic area. A more balanced development is evident when the New England REZ Transmission Link augmentation is developed, which benefits from the high resource quality in the New England REZ as well as diversity between the two REZs.

[11] For further details, see the 2021 Inputs and assumptions workbook that accompanies the IASR, at https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-inputs-assumptions-and-scenarios-report.pdf?la=en.

Figure 20 Comparison of New South Wales VRE development by 2028-29 – CDP7 vs 1, *Step Change* scenario



The modest net benefits of proceeding with New England REZ Transmission Link augmentation within an actionable timeframe rely on being able to allocate a much greater level of development in the Central West REZ and the NSW Non-REZ if the New England REZ Transmission Link is not available until two years later. Such a concentrated development of New South Wales VRE within a single location may have greater social license concerns that are not explicitly considered in the assessment.

Sydney Ring (Reinforcing Sydney, Newcastle, and Wollongong Supply)

The Sydney Ring increases the transfer capability into the Sydney, Newcastle, and Wollongong area, and provides the ability to continue to supply load in this area as coal retires.

In all scenarios other than the *Slow Change* scenario, issues with supply to Sydney are observed in line with the earliest development for the Sydney Ring augmentation project in 2027-28. If this reinforcement was not developed at the time of this need, there are significant additional costs due to additional capacity development and gas generation, and the benefits of other network augmentations in New South Wales are limited.

This is demonstrated by a comparison between CDP1 and CDP4, which differ only with regards to the actionable status of the Sydney Ring reinforcement project. This comparison, shown in Table 30, shows regrets associated with delaying the augmentation beyond its actionable in three of the four scenarios, and on a scenario-weighted basis.

Table 30 Comparing net market benefits in CDP1 and CDP4 ($ billion) – Sydney Ring

Scenario	CDP1 - with Sydney Ring actionable	CDP1 - without Sydney Ring actionable	Regret of "waiting and seeing", rather than acting now
Step Change	25.50	25.41	0.09
Progressive Change	16.72	16.50	0.22
Hydrogen Superpower	68.95	68.73	0.21
Slow Change	4.17	4.34	-0.17
Weighted Net Market Benefits	29.49	29.35	0.14

Table 31 examines the regret and weighted regret associated with CDP1 and CDP4. Both CDPs show some level of regret in *Step Change* and *Hydrogen Superpower* (reflecting the greater degree of early actionable investment preferred in these two scenarios). Delaying the Sydney Ring reinforcement results in a higher worst weighted regret, due to its impact on *Hydrogen Superpower.* The additional regret of not proceeding with the project immediately in *Step Change* also illustrates the risk of underinvestment.

Table 31 Comparing the weighted regret of CDP1 and CDP4 ($ million)

CDP Number	*Step Change*	*Progressive Change*	*Hydrogen Superpower*	*Slow Change*	Worst Weighted Regret
Regret: CDP1 – progress now	93	0	1588	168	-
Weighted Regret: CDP1	47	0	270	7	270
Regret: CDP4 – wait and see	181	221	1802	0	-
Weighted Regret: CDP4	90	64	306	0	306

In the modelling presented above, the development of storage is optimised between the different sub-regions of New South Wales, with both the early and delayed Sydney Ring augmentation.

An additional sensitivity was used to test whether a more concentrated development in Sydney would reduce the benefit of this development. This sensitivity forced the entirety of the 2 GW requirement for long-duration storage development in New South Wales to be located within Sydney in the *Progressive Change* scenario. As shown in Table 32, even considering this forced storage development, an early reinforcement of the Sydney Ring continues to deliver additional net market benefits.

Table 32 Sensitivity testing the impact of storage development concentrated in the Sydney area in the *Progressive Change* scenario

	Net market benefits ($ billion)
CDP1 (with optimised storage development)	16.72
CDP4 (with optimised storage development)	16.50
CDP4 (with storage development contracted in the Sydney area)	16.33

A6.6.1 Assessing the actionable status of Marinus Link

Costs and benefits of an actionable Marinus Link timing across the scenarios

All scenarios include the development of both the first and second cable of Marinus Link at some point in their least-cost DP. Both the *Step Change* and *Hydrogen Superpower* scenarios have an optimal timing of the first cable of Marinus Link that requires the project to be progressed as actionable (2027-28).

A comparison of CDP1 and CDP5 provides the ability to explore the risks of over- and under-investments associated with an actionable Marinus Link. As expected, Table 33 shows that an actionable Marinus Link delivers additional net market benefits in the *Step Change* and *Hydrogen Superpower* scenario, but not in the *Progressive Change* and *Slow Change* scenarios.

Table 33 Comparing net market benefits in CDP1 and CDP5 ($ billion) – Marinus Link

Scenario	CDP1 – Without ML actionable	CDP5 – With ML actionable	Regrets of "waiting and seeing" rather than acting now
Step Change	25.50	25.51	0.01
Progressive Change	16.72	16.51	-0.21
Hydrogen Superpower	68.95	69.60	0.65
Slow Change	4.17	3.71	-0.46
Weighted Net Market Benefits	29.49	29.52	0.04

As shown above, proceeding with Marinus Link as an actionable project in 2027-28 is regretful in both *Progressive Change* and *Slow Change*. However, in the *Step Change* the actionable timing is marginally more beneficial than a delayed timing (in *Step Change*, if Marinus Link was not actionable the optimal timing shifts to 2029-30, the next earliest possible date after a delay).

0 compares the benefits provided by an early Marinus Link development between the *Progressive Change* and *Step Change* scenarios. The key differences are:

- Gross market benefits are higher in the *Step Change* scenario due to higher generator capital cost savings. These benefits are primarily due to reducing the scale of VRE investment needed on the mainland due to the ability to use Tasmania's hydro storages and high-quality wind generation sites more effectively. The more rapid pathway to net zero emissions of the *Step Change* scenario means that these benefits are realised earlier than in the *Progressive Change* scenario.
- The additional transmission costs in the *Step Change* scenario are lower in NPV terms as the optimal deferred timing (2029-30) is one year earlier than in the *Progressive Change* scenario (2030-31).

Table 34 Comparing the impact of an actionable Marinus Link timing between the *Progressive Change* and *Step Change* scenario

Class of market benefit	Net benefit (NPV, $ million) of actionable Marinus Link vs delayed Marinus Link	
	Step Change	*Progressive Change*
Generator and storage capital deferral	156	21
FOM cost savings	3	-43
Fuel cost savings	128	176
VOM cost savings	12	4
USE+DSP reductions	17	3
Other Network investment (REZ augmentations)	-13	8
Gross market benefits	303	170
Network (Actionable and Future ISP Projects)	-293	-376
Total net market benefits	10	-207

The extract from Table 17 presented in Table 35 shows that in comparison to CDP1, CDP5 (which has an actionable Marinus Link timing) is more highly ranked on both ranking methodologies.

The calculation of the LWWR for each CDP is provided in Table 36, and shows that the larger regret in the *Hydrogen Superpower* scenario is driving the higher ranking of CDP5 under the LWWR approach, despite the relatively low scenario weighting of the scenario. In the *Hydrogen Superpower* scenario, the more rapid retirement trajectory results in much great capital cost reductions from an early Marinus Link which helps to offset the need for additional firm capacity and VRE on the mainland.

This comparison does not take into account other costs that may be associated with delaying the project, and then restarting the process at a later date. Any consideration of these costs would further increase the benefits of Marinus Link as an actionable project.

Table 35 Comparing CDP1 and CDP5 using the ranking methodologies ($ billion)

CDP Number	*Step Change*	*Progressive Change*	*Hydrogen Superpower*	*Slow Change*	Weighted Net Market Benefits	WNMB Rank	Worst Weighted Regret	LWWR Rank
1 – wait and see	25.50	16.72	68.95	4.17	29.49	6	0.27	6
5 – progress now	25.51	16.51	69.60	3.71	29.52	4	0.16	4
Benefit of actionable ML	0.01	-0.21	0.65	-0.46	0.04	-	-	-

Table 36 Comparing the weighted regret of CDP1 and CDP5 ($ million)

CDP Number	*Step Change*	*Progressive Change*	*Hydrogen Superpower*	*Slow Change*	Worst Weighted Regret
Regret: CDP1 – wait and see	93	0	1588	168	-
Weighted Regret: CDP1	47	0	270	7	270
Regret: CDP5 – progress now	83	207	938	628	-
Weighted Regret: CDP5	42	60	160	25	160

A longer lead-time for Marinus Link increases the regret of not proceeding

In November 2021, AEMO was informed by TasNetworks that the earliest installation date of Marinus Link could be delayed by up to two years as a result of the effects of COVID-19 on global supply chains. This updated assumption was not able to be applied across all of the modelling, but some additional analysis was undertaken to consider the impact this would have on the regrets of not proceeding with Marinus Link as an actionable project.

CDP1 and CDP5 were re-simulated with the delivery timeframe of Marinus Link delayed two years, meaning that if actionable the project could be delivered in 2029-30 or 2030-31, but if not, then it would not be available for delivery until 2031-32 (assuming the project is actionable in the 2024 ISP).

The outcome of this additional analysis is provided in Table 37. The regret of not proceeding with an actionable Marinus Link timing is greater in all scenarios than the original assumption, as waiting until the 2024 ISP would mean it is delivered too late in *Step Change* and *Hydrogen Superpower*.

Table 37 Impact of delaying future Marinus Link timings ($ billion)

Scenario	CDP1 (with future ML not available until at least 2032)	CDP5 (with actionable ML timing delayed to 2030)	Regrets of "waiting and seeing" rather than acting now
Step Change	25.15	25.50	0.35
Progressive Change	16.61	16.7	0.09
Hydrogen Superpower	68.26	68.95	0.69
Slow Change	4.17	3.95	-0.23
Weighted Net Market Benefits	29.17	29.47	0.31

A6.6.2 Assessing the actionable status of VNI West

Costs and benefits of an actionable VNI West timing across the scenarios

The optimal timing of VNI West varies across the four key scenarios. In both the *Step Change* and *Hydrogen Superpower* scenarios, it is optimal at an actionable timing (2031-32 and 2030-31 respectively). However, the optimal timing is delayed considerably in both the *Progressive Change* and *Slow Change* scenarios.

A comparison of CDP2 and CDP5 provides a view of the regrets associated with over- and under-investment in VNI West as an actionable project. If actionable, VNI West would be operational at the optimal timing in the *Step Change* and *Hydrogen Superpower* scenarios, but brought forward in the *Progressive Change* and *Slow Change* scenarios. In CDP5, the project is not actionable and therefore the earliest timing is pushed back to 2032-33. The net market benefits of the CDPs are compared in 0, along with their ranking under the two ranking methodologies.

Table 38 Comparing CDP2 and CDP5 using the ranking methodologies ($ billion)

CDP Number	*Step Change*	*Progressive Change*	*Hydrogen Superpower*	*Slow Change*	Weighted Net Market Benefits	WNMB Rank	Worst Weighted Regret	LWWR Rank
2 – progress now	25.59	16.26	70.01	3.25	29.54	3	0.13	2
5 – wait and see	25.51	16.51	69.60	3.71	29.52	4	0.16	4
Benefits of an actionable VNI West	0.08	-0.25	0.42	-0.46	0.02			

This table shows that the addition of an earlier VNI West (in actionable timeframe) results in a higher ranking under both CBA approaches. Table 39 presents the regrets associated with CDP2 and CDP5. A delayed VNI West results in a higher worst weighted regret, being most regretful in in *Hydrogen Superpower* due to the level of underinvestment it represents.

Table 39 Comparing the weighted regret of CDP2 and CDP5 ($ million)

CDP Number	*Step Change*	*Progressive Change*	*Hydrogen Superpower*	*Slow Change*	Worst Weighted Regret
Regret: CDP2 – progress now	0	457	519	1088	-
Weighted Regret: CDP2	0	133	88	44	133
Regret: CDP5 – wait and see	83	207	938	628	-
Weighted Regret: CDP5	42	60	160	25	160

The impact of Marinus Link on VNI West

While both Marinus Link and VNI West are needed as soon as possible to optimise benefits to consumers, some of the benefits provided by VNI West are similar to those provided by Marinus Link. The analysis presented above assumes that both Marinus Link cables are operational before VNI West is commissioned (as a result of the CDPs being compared).

There remains some uncertainty around the resolution of funding arrangements for Marinus Link. Should Marinus Link not be able to proceed, there are increased benefits of VNI West generally. This is shown in Table 40.

Table 40 Comparing the net market benefits of progressing VNI West now, with vs without Marinus Link ($ million)

CDP Number	*Step Change*	*Progressive Change*	*Hydrogen Superpower*	*Slow Change*	Weighted Net Market Benefits
With Marinus Link available	83	-250	419	-460	22
Without Marinus Link available	248	-108	735	-525	197
Additional benefits of an actionable VNI West	164	142	316	-65	175

VNI West provides additional resilience to early closures of brown coal

The regrets associated with delaying VNI West beyond an actionable timing in *Step Change* and *Hydrogen Superpower* indicates that earlier coal retirements are likely to increase the need for the project. The ability of VNI West to provide additional resilience to unexpected or earlier than forecast brown coal closures was further demonstrated through a sensitivity that assumed the retirement of Loy Yang A Power Station in 2031-32 in the *Progressive Change* scenario. Compared to the base case, progressing VNI West sooner than later in this sensitivity showed a substantial increase in net market benefits of $531 million, shown in Table 41.

Table 41 Net market benefits of progressing VNI West now, as insurance against early brown coal retirement ($ million)

Case	Net market benefits of actionable VNI West ($ million)
***Progressive Change* retirements**	-250
Early Loy Yang A retirement	281

Additional sources of market benefits for VNI West

Additional time-sequential modelling was applied to CDP2 and CDP5 due to the materiality of fuel cost savings in the capacity outlook modelling for these CDPs, and the potential for additional reliability benefits.

Modelling also explored the potential for competition cost savings and whether there were additional reliability benefits identified using more granular stochastic modelling. The results of this assessment are provided in Table 42, which show that when combined, these additional benefits are immaterial.

Table 42 Additional market benefits for an Actionable VNI West ($ million)

	Step Change	*Progressive Change*	Weighted*
Competition Benefits (indicative only)	-7	-24	-11
Reliability Benefits	4	23	9
Total additional Benefits	-3	-1	-2

* The competition and reliability benefits in the *Hydrogen Superpower* and *Slow Change* scenarios are assumed to be zero for the purpose of calculating weighted benefits.

VNI West delivers negative competition benefits in both scenarios due to the additional utility-scale storage that would be required if VNI West was not progressed within an actionable timeframe. This storage is expected to displace higher-cost generation such as gas during periods of supply scarcity, particularly in the evening, which would increase competition for dispatch for incumbent generators. This reduces the incentive for strategic players to withdrawal capacity – it is no longer such a profit-maximising strategy. The increase in competition in the counterfactual due to development of new storage capacity is greater than the increase competition due to the early delivery of VNI West, and therefore competition benefits are slightly negative.

The relatively small improvement in reliability when VNI West is progressed in an actionable timeframe indicates that the capacity outlook modelling is effectively delivering an outcome that provides a similar level of reliability with and without VNI West as actionable.

The case for proceeding with a staged VNI West to minimise regret

The analysis above demonstrates that an actionable VNI West delivers positive net market benefits on a weighted basis and is also superior when considered using the LWWR approach. However, the benefits vary between scenarios, such that there is regret from not proceeding in *Step Change* and *Hydrogen Superpower* (risk of under-investment), and regret from fully committing to the project in *Progressive Change* and *Slow Change* (risk of over-investment).

Given this uncertainty, AEMO has considered whether project staging through the use of early works delivers a better outcome for consumers by helping to mitigate these risks. The early works for VNI West are assumed to cost $491 million, of which $25 million would need to be re-spent at a later date if the project was delayed for an extended period (as is currently optimal in the *Progressive Change* and *Slow Change* scenarios). It is assumed that staging does not result in additional costs in scenarios where stage 2 follows immediately from stage 1.

The benefit of this staging is that it preserves the ability to deliver a project at an actionable timing if required, and introduces option value for a project to pause if future circumstances do not warrant early completion. The early works stage provides opportunity for the project proponent to identify cost savings, reduce cost uncertainties, and provide greater consumer confidence that they will not be over- or under-investing.

In the case of VNI West, the benefits of proceeding with staging are as follows:

- In the *Step Change* and *Hydrogen Superpower* scenarios, VNI West can be delivered at its optimal timing without additional cost, maximising net market benefits for consumers. In more general terms, it allows a more accelerated delivery to mitigate the impact of early coal closures.
- In the *Progressive Change* and *Slow Change* scenarios, the risk to consumers of over-investment is minimised by committing to a smaller investment of which the majority would still be retained even if the project were delayed.

The cost of early works in a scenario that defers the project has two components:

- A cost associated with spending money earlier than it would otherwise need to have. This results in a higher cost in NPV terms compared to delaying that expenditure to a future period.
- The costs associated with re-spend (for example, money paid for options to purchase land which then expire).

CDP10 considers the addition of a staged actionable VNI West, in addition to an actionable Marinus Link, New England REZ Transmission Link, and the Sydney Ring. Comparing CDP10 with CDP5 provides an ability to consider the value provided by proceeding with the first stage rather than waiting to reassess in the 2024 ISP. A further comparison with CDP2 shows whether staging is superior to proceeding with the full project now. These comparisons are provided in 0.

Table 43 Assessing the net market benefits of VNI West options ($ billion)

CDP Number	*Step Change*	*Progressive Change*	*Hydrogen Superpower*	*Slow Change*	Weighted Net Market Benefits	WNMB Rank	Worst Weighted Regret	LWWR Rank
5 – wait and see	25.51	16.51	69.60	3.71	29.52	4	0.16	4
2 – progress now in full	25.59	16.26	70.01	3.25	29.54	3	0.13	2
10 – staged VNI West	25.59	16.35	70.01	3.52	29.58	1	0.11	1

This shows that the addition of VNI West staging means CDP10 is the highest ranked path under both ranking methodologies and delivers an additional $40 million of net market benefits over proceeding now with VNI West without any staging. Effectively, the early works eliminate any regret of not expediting the project in the more rapidly decarbonising scenarios, while reducing the cost in comparison to proceeding with the full project in the *Progressive Change* and *Slow Change* scenarios.

Table 44 presents the regrets by scenario and worst weighted regrets for the three CDPs. As already seen in Table 39 and replicated below, an actionable VNI West (CDP2) reduces overall regret in *Hydrogen Superpower* and *Step Change*, while increasing it in *Progressive Change* and *Slow Change*. Given how regretful investment delay is in *Hydrogen Superpower,* CDP2 is ranked higher on a LWWR basis.

A staged VNI West further reduces worst weighted regrets, and results in the highest LWWR ranked CDP. By providing the option for VNI West to be delivered at an actionable timing through a staged project, regrets in *Step Change* and *Hydrogen Superpower* in CDP10 are the same as in CDP2, and therefore lower than in CDP5. However, the staging of VNI West also reduces the regret associated with over-investment in *Progressive Change* and *Slow Change*.

Table 44 Comparing the weighted regrets of CDP5, CDP2 and CDP10 ($ million)

CDP Number	*Step Change*	*Progressive Change*	*Hydrogen Superpower*	*Slow Change*	Worst Weighted Regret
Regret: CDP5 – wait and see	83	207	938	628	-
Weighted Regret: CDP5	42	60	160	25	160
Regret: CDP2 – progress now in full	0	457	519	1088	-
Weighted Regret: CDP2	0	133	88	44	133
Regret: CDP10 – staged VNI West	0	368	519	821	-
Weighted Regret: CDP10	0	107	88	33	107

Furthermore, the additional benefits of staging VNI West as a result of continued uncertainty around the funding arrangements of Marinus Link (Table 40) and additional resilience to early coal retirements (demonstrated by Table 41) would further improve the value of a staged VNI West.

A6.6.3 Assessing the benefits provided by HumeLink

Costs and benefits of an actionable HumeLink timing across the scenarios

The optimal timing of HumeLink varies between the scenarios, and is strongly linked to coal closures, particularly in New South Wales. As such, scenarios with a faster transition towards net zero emissions result in earlier optimal timing for HumeLink. The *Hydrogen Superpower* scenario incorporates rapid transformation which identifies the greatest benefit of the project with an actionable timing, while *Step Change* is slightly slower (2028-29).

A comparison between CDP10 and CDP11 (shown in Table 45) shows:

- There are considerable regrets to an actionable HumeLink timing in the *Progressive Change* and *Slow Change* scenarios, representing over-investment in these scenarios.
- Adding HumeLink at an actionable timing is not a high ranked CDP under either methodology when assessed across all scenarios (although it remains in the top 10 ranked CDPs).

- Commissioning HumeLink in 2026-27 results in a reduction in weighted net market benefits of $284m, compared to waiting for reassessment in the 2024 ISP.

Table 45 Comparing CDP11 and CDP10 using the ranking methodologies ($ billion)

CDP Number	*Step Change*	*Progressive Change*	*Hydrogen Superpower*	*Slow Change*	Weighted Net Market Benefits	WNMB Rank	Worst Weighted Regret	LWWR Rank
11 – progress now	25.39	15.66	70.20	3.13	29.30	9	0.31	7
10 – wait and see	25.59	16.35	70.01	3.52	29.58	1	0.11	1
Regret of a delayed HumeLink	-0.20	-0.69	0.18	-0.39	-0.28			

As seen in Table 45, the regrets associated with delaying HumeLink until at least 2028-29 are lower than if the project was committed in full to its earliest delivery schedule. However, this analysis does not consider regret associated with finding the project is delivered too late, which could occur if: coal closes earlier than projected, schedule slippage delays project delivery, or other medium-duration storage does not materialise as quickly as hoped to replace coal. Further analysis to quantify the risk of schedule slippage is considered in determine the option value associated with staging (see below).

Consideration of (indicative) competition benefits and reliability benefits

TransGrid's RIT-T Project Assessment Conclusions Report (PACR) identified considerable competition benefits attributable to HumeLink. AEMO's capacity outlook modelling also identified that there are material fuel cost savings associated with HumeLink, and that the reliability cost savings provided by HumeLink are a key driver of its market benefits. As such, AEMO has assessed the CDP10 and CDP11 in more detail using time-sequential modelling in the *Progressive Change* and *Step Change* scenarios.

This modelling quantified the potential competition cost savings and any additional reliability benefits that were not captured using the capacity outlook model. The results of this assessment are provided in Table 46.

Table 46 Additional market benefits for progressing HumeLink as soon as possible ($ million)

	Step Change	*Progressive Change*	Weighted
Competition Benefits (indicative only)	64	216	95
Reliability Benefits	8	66	23
Total additional Benefits	73	282	118

While not included in the cost benefit analysis, indicative modelling suggests that HumeLink delivers competition cost benefits in both scenarios by enabling additional peaking capacity to serve load centres in New South Wales. During periods of supply scarcity HumeLink provides access to Snowy 2.0 and other lower cost generation sources, improving the competitive balance of supply and demand and reducing reliance on more expensive sources of dispatchable capacity.

Competition cost savings are higher in the *Progressive Change* scenario and can be monetised over a longer timeframe (that is, the difference between optimal and actionable timing). A slower retirement schedule of the strategic players in *Progressive Change* relative to *Step Change* means that greater strategic withholding of generation in periods of supply scarcity may occur in *Progressive Change*, leading to greater competition cost savings from the project.

Under the *Step Change* scenario withholding strategies have less impact and are short lived given the faster pace at which coal capacity retires and is replaced by lower cost generation and storage. Savings are smaller also given the similarity in HumeLink timing between CDP10 and CDP11.

In the *Progressive Change* scenario, HumeLink also provides material additional reliability benefits that were underestimated by the capacity outlook model. Considering these reliability benefits, the impact of bringing forward HumeLink to 2026-27 increases net market benefits from -$284 million to -$260 million.

Considering the benefits of a staged delivery of HumeLink

Given that HumeLink is required at the earliest timing in the *Hydrogen Superpower* scenario, and shortly thereafter in the most likely *Step Change* scenario, AEMO has considered the merits of proceeding with HumeLink as a staged actionable project. Consideration of the risk of schedule slippage and/or further coal closures indicates that staging the project targeting delivery by 2026-27 but allowing for flex in this timing if circumstances change, optimises benefits to consumers.

Benefit of project staging in preserving flexibility

As with VNI West, the benefit of this staging is that it preserves the ability to deliver a project as early as possible if required, but also allows a project to be deferred if it becomes evident that a later delivery timing would deliver greater benefits to consumers. It also provides opportunities to reduce uncertainty around cost estimates and ideally bring the project costs down.

Transgrid's preliminary high-level estimate for early works is $330 million, based on a top-down estimate which is being reviewed, developed and refined for a planned contingent project application submission of next year to both:

- improve the accuracy of which project scope activities will be undertaken in early works versus stage 2, and
- improve the accuracy of the early works cost estimates by undertaking a bottom up, project-specific estimate.

Delaying the project development, resulting in a pause to land option agreement negotiation and route selection, engineering and early contractor engagement activities, and stakeholder engagement and community consultation has also been estimated by Transgrid on a top-down basis to cost an additional $50 million.

It is assumed that staging does not result in additional costs in scenarios where stage 2 follows immediately from stage 1.

The benefits of proceeding with HumeLink as a staged actionable project are that it:

- Minimises regret in the *Hydrogen Superpower* scenario by allowing an early HumeLink delivery at the timing that is optimal for consumers. This could also be categorised as minimising regret for consumers to more accelerated coal retirements than forecast in the *Step Change* scenario.

- Minimises the risk to consumers of over-investment to deliver to a timetable that is not necessary under the *Progressive Change* and *Slow Change* scenarios. The works will create an additional protection for consumers by providing a further decision point before committing to the full project funding.
- Minimises the risks of an extended delay should the project lose momentum in the *Step Change* scenario.

Considering the risk of schedule slippage

Table 47 shows the net market benefits associated with the staging of HumeLink with early works progressed now, enabling the option for it to be delivered at its optimal timing in all scenarios (CDP12). The net market benefits are compared to taking no action in this ISP (CDP10) and for progressing with the full project now (CDP11). The risk of a two-year project delay due to schedule slippage is also included.

Table 47 Assessing the benefits of HumeLink as a staged actionable project, including consideration of schedule slippage

Scenario	Weighted net market benefits ($ billion)					
	No schedule slippage			Schedule slippage leading to 2-year delay†		
	Staged actionable project for delivery in 2026-27 (CD12)	No action, delivery from 2028-29 (CDP10)	Full project progressed now, delivery in 2026-27 (CDP11)	Staged actionable project with delivery in 2028-29 (CD12)	No action, delivery from 2030-31 (CDP10)	Full project progressed now, with delivery in 2028-29 (CDP11)
Step Change	25.59	25.59	25.40	25.59	25.40	25.59
Progressive Change	16.20	16.35	15.73	16.20	16.35	16.02
Hydrogen Superpower	70.20	70.01	70.20	70.01	69.44	70.01
Slow Change	3.35	3.52	3.13	3.35	3.52	3.36
Weighted	29.56	29.58	29.32	29.53	29.39	29.48

* This includes $149 million of early works cost in the *Progressive Change* scenario and $166m of early works cost in the *Slow Change* scenario but assumes that simply slowing down the construction timeline in *Step Change* comes at no additional cost to consumers. Early works costs are higher in Slow Change given the further delay to project completion. These costs are lower than the reported $330 million early works reflecting the fact that the work needs to be completed at some stage, and therefore it is only the bring-forward cost of this work that needs to be accounted for discretely.
†This value considers additional reliability benefits .

Assuming no schedule slippage, CDP12 ranks second on the basis of weighted net market benefits, and third on LWWR, in both cases only marginally less beneficial than the highest ranked CDP11 (see Table 17)[12]. This marginal additional insurance cost of $ 20 million (CDP10 – CDP12) provides flexibility to respond to accelerated net zero ambition or coal retirements, as well as managing the risk of extended project delays. For example, if there is schedule slippage leading to a two-year delay in project delivery, CDP12 ranks highest on the basis of weighted net market benefits, and there is considerable regret to not proceeding with early works on HumeLink.

There would only need to be a 10% chance of schedule slippage resulting in a two-year delay for the staged actionable project to optimise benefits for consumers, targeting a 2026-27 implementation to provide delivery risk contingency.

[12] The assessment of CDP12 does not include any additional reliability benefits given that the timing of HumeLink between CDP11 and CDP12 is unchanged in the *Progressive Change* and *Step Change* scenarios.

Staged project provides increased resilience to early coal closures

A further sensitivity was simulated that explored the impact of assuming earlier coal closures in New South Wales in both *Progressive Change* and *Step Change.* In this sensitivity, four New South Wales coal generators are assumed to all be retired by 2027-28. Table 48 shows that in both scenarios there is a positive net market benefit from the 2026-27 delivery in the event of the early coal closures, further demonstrating that a staged project targeting delivery by 2026-27 helps mitigate against this risk. A similar impact is likely if some of the medium storage of eight hours duration needed to help meet the objectives of the New South Wales roadmap did not materialise ahead of the projected coal closures.

The substantial increase in benefits in *Progressive Change* is because the earlier coal closures require approximately 2 GW more firming capacity without HumeLink compared to if HumeLink were delivered by 2026-27. The lesser impact in *Step Change* is because of the smaller difference in timings (2026-27 versus 2028-29).

Table 48 Assessing the benefits of HumeLink as an actionable project delivered in 2026-27 compared to optimal timings in base case

Scenario	Weighted net market benefits ($ million)	
	With original coal closure timings*	With early coal closures
Progressive Change	-619	464
Step Change	-192	16

* Includes additional reliability benefits

A6.6.4 Considering the benefits of the Gladstone Grid Reinforcement project

The least-cost DP of all scenarios results in the development of Gladstone Grid at a timing linked to the closure of Gladstone Power Station. The retirement of Gladstone Power Station is accelerated in the *Hydrogen Superpower* scenario compared to other scenario due to the need to meet more aggressive emissions reduction requirements, with all Gladstone units retired by 2028-29. Linked to this accelerated Gladstone Power Station closure timing, the *Hydrogen Superpower* scenario has an optimal timing of the Gladstone Grid Reinforcement project that requires the project to be progressed now, in an actionable timeframe.

However, in no other scenario is there any benefit to this actionable timing, as shown in Table 49. This table compares CDP3 with CDP8, which share all the same actionable projects except that CDP8 does not feature an actionable Gladstone Grid Reinforcement.

Table 49 Determining the benefits of progressing with Gladstone Grid reinforcement now ($ billion)

Scenario	CDP3	CDP8	Regret associated with delaying Gladstone Grid project beyond actionable timing
Step Change	25.34	25.39	-0.05
Progressive Change	15.47	15.56	-0.08
Hydrogen Superpower	70.53	70.20	0.34
Slow Change	2.51	2.87	-0.35
Weighted Net Market Benefits	29.25	29.26	-0.01

As stated above, the *Hydrogen Superpower* scenario does show that an actionable Gladstone Grid Reinforcement delivers considerable net market benefits, and thus it is the only scenario where delaying the project is associated with positive regret. The negative regrets are largest in the *Slow Change* scenario as this reinforcement is never needed given the assumed retirement of the Boyne Island smelter.

On balance, this comparison suggest that net market benefits are effectively equivalent between the two CDPs. More importantly, the analysis indicates the critical importance of aligning the Gladstone Grid Reinforcement to be available at or before the retirement of Gladstone Power Station, assuming Boyne Island smelter would continue to operate. The timing of the retirement of any individual power station (as well as any large industrial load) will always be uncertain until a firm closure date is announced.

AEMO will therefore continue to work with Powerlink and the Queensland Government to consider what options are available to best manage these uncertainties which will inform the Final ISP, noting that this project does not materially impact any of the other ISP projects considered in this Draft ISP.

A6.6.5 Sensitivity to transmission costs

The ISP Methodology set out an approach to applying TOOT analysis for the purpose of providing a guide on the sensitivity of the actionability of projects to transmission cost variations. This section provides the outcomes of that analysis, but also expands beyond that. In general, all of the projects that are actionable in the draft ODP deliver increasing benefits in the later years of the horizon, and as such deliver large net benefits when compared with their TOOTs, indicating that positive net market benefits could still be delivered at substantially higher costs. However, this analysis does not consider that a higher transmission cost may mean that although a project is still beneficial when assessed over the full horizon, the optimal timing could be later, and beyond the actionable timing.

AEMO has therefore explored the impact that increased transmission costs can have on the timing of actionable projects identified in the optimal development path. This analysis considers whether an actionable timing still delivers positive net market benefits over a later timing at a higher assumed cost. These costs have been derived based on the upper end of the cost range published in the 2021 *Transmission Cost Report*[13]. Only the upper cost range has been applied here, given the purpose is to explore robustness to cost increases, as assumed cost reductions would of course only increase the benefits of an actionable timing.

New England augmentations

As outlined in Section A6.5.2, the overall benefits of New England augmentations are significant. Under the *Step Change* scenario, sequential augmentations to New England (both the Transmission Link and the Extension projects) are expected to deliver $5.5 billion in net market benefits compared to a DP that removes the augmentations entirely (a “TOOT”).

Given the magnitude of the benefits under this TOOT analysis, it is more valuable to instead consider the sensitivity to transmission cost increases with regards to whether the Transmission Link project should be delivered in an actionable timeframe or not.

As seen in Table 50, an actionable New England REZ Transmission Link (distinguished as the difference between CDP1 and CDP7) is found to result in net market benefits across all scenarios, with a weighted net

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

market benefit of $113 million. Applying a 50% cost increase, the augmentation is no longer found to be preferred at an actionable timing in the *Step Change* and in *Progressive Change* scenarios. There are also reductions in benefits in the *Hydrogen Superpower* and *Slow Change*.

The weighted net market benefits of an actionable timing are still marginally positive given how beneficial it is in the *Hydrogen Superpower* scenario, where the augmentation also helps facilitate interconnector flows between Queensland and New South Wales.

Table 50 Net market benefits ($ million) of progressing New England REZ Transmission Link now vs later – cost sensitivity

Net market benefits from actionable timing vs delayed timing	*Step Change*	*Progressive Change*	*Hydrogen Superpower*	*Slow Change*	Weighted Net Market Benefits
Current cost assumptions	14	43	494	236	113
With 50% cost increase	-95	-45	406	148	15

Sydney Ring

The Sydney Ring was demonstrated in Section A6.5.2 A6.6to deliver net market benefits of $3.4 billion when compared to a TOOT development path without the project. Given the increasing market benefits (as seen in Figure 13) throughout the horizon, the alternative approach that assesses the sensitivity of the optimal timing of the project to an increase in transmission costs is more informative. The value of an actionable Sydney Ring is shown through a comparison between CDP4 and CDP1, which are equivalent except for the actionability of this augmentation.

Table 51 shows the impact of a 50% increase in the cost of Sydney Ring on its value in progressing now. With a 50% increase in cost, the *Step Change*, *Progressive Change* and *Hydrogen Superpower* scenarios still see an increase in net market benefits associated with an actionable timing, albeit a smaller one. In comparison, the increase in negative net market benefits in the *Slow Change* scenario is substantial. However, weighted across the scenarios, weighted net market benefits remain positive for the actionable timing.

Table 51 Net market benefits ($ million) of progressing Sydney Ring now vs later - cost sensitivity

Net market benefits from actionable timing vs delayed timing	*Step Change*	*Progressive Change*	*Hydrogen Superpower*	*Slow Change*	Weighted Net Market Benefits
Current cost assumptions	88	221	214	-168	138
With 50% cost increase	47	181	174	-474	86

Marinus Link

Table 52 shows the impact of applying a 15% cost increase (to both Marinus Link cables) when comparing an actionable timing to a delayed timing (rather than to a TOOT). The actionable timing now delivers negative net market benefits in the *Step Change* scenario and weighted across all scenarios. This would indicate that were costs to increase to this extent and ignoring some of the other relevant considerations outlined in Section A6.6.1, a delayed Marinus Link timing may be preferred.

Table 52 Net market benefits ($ million) of progressing Marinus Link now versus later – cost sensitivity

Net market benefits from actionable timing vs delayed timing	*Step Change*	*Progressive Change*	*Hydrogen Superpower*	*Slow Change*	Weighted Net Market Benefits
Current cost assumptions	10	-207	649	-460	37
With 15% cost increase	-34	-263	605	-679	-18

VNI West

Section A6.5.2 explored the benefits provided by an actionable VNI West compared to a TOOT. In particular, VNI West provided generator capital cost savings that arise due to a reduced need for new firming generation in Victoria and South Australia. In the *Step Change* scenario, Figure 15 showed that net market benefits increased throughout the horizon, with an NPV of $1.9b.

Despite the size of the overall benefit, the optimal timing of VNI West differed between the scenarios, and Section A6.6.2 explored the value of project staging in providing the flexibility to deliver VNI West at a beneficial timing.

Table 53 below presents the change in net market benefits that arise as a result of an actionable VNI West augmentation under the original cost assumptions and with a 10% and a 30% cost increase. VNI West continues to deliver positive net market benefits in *Step Change* and *Hydrogen Superpower* under these increased costs, though less than before. In the *Progressive Change* and *Slow Change*, an actionable VNI West now further decreases net market benefits.

The reduction in these last two scenarios, coupled with the lower benefits in *Step Change* and *Hydrogen Superpower* show that with the current uncertainty around the speed of emissions reduction in particular, it would no longer be beneficial to proceed with the project at an actionable timeframe under a 10% cost increase, or with a 30% cost increase.

Table 53 Net market benefits ($ million) of progressing VNI West now versus later – cost sensitivity

Net market benefits from actionable timing vs delayed timing	*Step Change*	*Progressive Change*	*Hydrogen Superpower*	*Slow Change*	Weighted Net Market Benefits
Current cost assumptions	83	-250	419	-460	22
With 10% cost increase	72	-318	396	-543	-10
With 30% cost increase	50	-453	350	-708	-75

If there were greater certainty that Australia was proceeding on a path consistent with *Step Change* and *Hydrogen Superpower*, and the focus is instead limited to these scenarios, VNI West would provide net market benefits in proceeding, even assuming a 30% cost increase.

HumeLink

As discussed in Section A6.6.3, the optimal timing of HumeLink is closely linked to coal retirements in New South Wales. The net market benefits of HumeLink at the optimal timing within each scenario compared to a TOOT was $1.3 billion and $0.86 billion in the *Step Change* and *Progressive Change* scenarios respectively, and HumeLink was beneficial in all scenarios. However, as detailed in Section A6.6.3, HumeLink does not deliver positive net market benefits at actionable timing compared to a later timing when assessed across all scenarios if not through a staged investment.

Table 54 presents the change in net market benefits as a result of an actionable HumeLink timing for the base case assumptions and assuming a 30% cost increase. Under this higher cost assumption, delivering HumeLink in 2026-27 would result in significant reductions in net market benefits in all scenarios, particularly those where HumeLink is preferred at a much later timing.

Table 54 Net market benefits ($ million) of progressing HumeLink now versus later – cost sensitivity*

Net market benefits from actionable timing vs delayed timing	*Step Change*	*Progressive Change*	*Hydrogen Superpower*	*Slow Change*	Weighted Net Market Benefits
Current cost assumptions	-192	-619	184	-394	-260
With 30% cost increase	-290	-985	87	-819	-448

* Includes additional reliability benefits

A6.7 Testing the resilience of the candidate development paths

A6.7.1 Sensitivity to lower gas prices

AEMO committed to testing a low gas price sensitivity in the 2021 IASR. This sensitivity considers a lower bound on gas prices and was applied to the *Progressive Change* and *Step Change* scenarios, which together account for the majority of the scenario weighting.

For this sensitivity analysis, a selection of CDPs were re-modelled to explore the impact of a lower gas price on some of the major projects (Marinus Link, VNI West and HumeLink), where a material source of benefits was due to avoided fuel costs. Comparing the differences in these CDPs between the base case and low gas price sensitivity provides an ability to understand how robust the top ranked CDPs are to lower gas prices. The comparisons are as follows:

- The comparison of CDP5 with CDP1 provides an understanding of the sensitivity of Marinus Link to lower gas prices.
- Comparing CDP2 with CDP5 allows a consideration of the impact of gas prices on the benefits provided by VNI West.
- Comparing CDP8 with CDP2 quantifies the impact of lower gas prices on the benefits provided by HumeLink.

As seen in Table 55, a lower gas price reduces net market benefits relative to the counterfactual across all CDPs. The majority of this reduction is due to the reduction in costs in the counterfactual under the low gas price sensitivity given that gas generation is more significant in the counterfactual than in any of the CDPs.

CDP rankings are relatively robust to gas prices, as shown in the table below. In particular, CDP10 and CDP12 remain the first and second ranked under the weighted net market benefits approach. This shows that under both methodologies, the rankings are unchanged as a result of the lower gas prices.

Table 55 Net market benefits by CDP and scenario in the base case and low gas price sensitivity (net market benefits, $ billion)

	Base assumptions				Low gas price			
CDP	*Step Change*	*Progressive Change*	Weighted NMB	Weighted Ranking (of this selection)	*Step Change*	*Progressive Change*	Weighted NMB	Weighted Ranking (of this selection)
1	25.50	16.72	29.49	5	22.87	13.33	27.19	5
2	25.59	16.26	29.54	3	22.93	12.81	27.21	3
5	25.51	16.51	29.52	4	22.86	13.11	27.21	4
8	25.39	15.56	29.26	7	22.71	12.08	26.91	7
10	25.59	16.35	29.58	1	22.93	12.95	27.27	1
11	25.39	15.66	29.30	6	22.71	12.24	26.96	6
12	25.59	16.20	29.56	2	22.93	12.80	27.25	2

The weighted net market benefits in this table include net market benefits from each scenario, with the *Slow Change* and *Hydrogen Superpower* scenario outcomes reflective of the base gas price assumptions.
The weighted rankings are relative to only the subset of CDPs, and exclude non-modelled CDPs.

Impact of low gas prices on Marinus Link timing

Comparing CDP5 and CDP1 in Table 55 shows the impact on the actionability of Marinus Link of lower gas prices. Lower gas prices reduce the net market benefits of an actionable Marinus Link in both scenarios, and on a weighted basis. However, this reduction is not sufficient to shift rankings within the CDP collection.

In the *Progressive Change* scenario, fuel cost savings that are due to reductions in gas generation are minimal. In the *Step Change* scenario, there are some cost savings that are due to reductions in gas generation, however the difference in gas prices between the base case and low gas price sensitivity are more minimal for *Step Change* scenario.

Impact of low gas prices on VNI West timing

Table 56 presents the impact on the actionability of VNI West of lower gas prices (the difference in net market benefits between CDP2 and CDP5). Lower gas prices reduce the net market benefits of an actionable VNI West timing in both scenarios, particularly the *Progressive Change* scenario where the impact equates to a 15% reduction in gross benefits. Impacts in the *Step Change* scenario are minimal given the smaller difference in gas prices and because the non-actionable timing is only one year after the actionable timing.

Table 56 Impact of progressing VNI West now versus later – low gas price sensitivity (net market benefit, $ million)

	Step Change	*Progressive Change*	Weighted NMB*
Base assumptions	83	-250	22
Low gas price	76	-309	1
Impact of lower gas prices on net market benefits	-8	-59	-21

*Applies base assumptions for *Hydrogen Superpower* and *Slow Change.*

Overall, an actionable VNI West still provides positive weighted net market benefits under the low gas price sensitivity, although marginally, at $1 million.

As seen in Table 55, CDP10 remains the highest ranked CDP. The weighted net market benefits provided by VNI West as a staged actionable project also remain relatively robust regardless of lower gas prices. The option value increases weighted net market benefits by $53 million, compared to $36 million in the base case (through a comparison of the weighted net market benefits in CDP10 and CDP2)

Impact of low gas prices on HumeLink timing

As seen in Table 57, lower gas prices have a minimal impact on the net benefits provided by an actionable HumeLink timing. The net market benefits of an early HumeLink timing reduces by an additional $31 and $19 million in the *Progressive Change* and *Step Change* scenarios respectively under a low gas price sensitivity, compared to the base case. The overall reduction in weighted net market benefits amounts to $18 million, as a result of low gas prices.

In the *Progressive Change* scenario, HumeLink does deliver material fuel cost savings attributable to reductions in gas generation. In the low gas price sensitivity, there is an increase in gas generation generally, as well as additional investment in peaking gas generators in favour of utility-scale storage. In the sensitivity, HumeLink results in greater reductions in gas generation than in the base case, although this reduction is less valuable in terms of net market benefits due to the lower fuel cost. These effects reduce the negative impact of lower gas prices on the net market benefits of HumeLink.

The same impacts are evident in the *Step Change* scenario, but to a lesser extent given the smaller difference in gas prices and the two-year difference in HumeLink timing between CDP11 and CDP10. However, the reduction in net market benefits is equivalent to a 15% reduction in gross benefits as a result of lower gas prices.

Table 57 Impact of progressing HumeLink now versus later – low gas price sensitivity (net market benefit, $ million)

	Step Change	*Progressive Change*	Weighted NMB*
Base assumptions	-192	-619	-260
Low gas price	-211	-651	-279
Impact of lower gas prices on net market benefits	-19	-31	-18

* Applies base assumptions for *Hydrogen Superpower* and *Slow Change,* and includes additional reliability benefits.

A6.7.2 Sensitivity to the discount rate

AEMO has included two sensitivities which explore the impact of higher discount rates:

- Increasing the discount rate from 5.5% to 10% as a means of exploring the robustness of the CDP rankings to a much higher discount rate.
- Increasing the discount rate to 7.5% on a selection of key CDPs.

Applying a 10% discount rate

Table 58 presents the performance of each CDP (that features Marinus Link[14]) when applying a 10% discount rate. Net market benefits are now lower across all CDPs and scenarios, due to the reduced present value of future market benefits, and the rankings differ slightly: CDP1 has the highest net market benefits but CDP5 has the LWWR.

Table 58 Performance of candidate development paths under a 10% discount rate across scenarios ($ billion) – ranked in order of weighted net market benefits

CDP Number	*Step Change*	*Progressive Change*	*Hydrogen Superpower*	*Slow Change*	Weighted Net Market Benefits	WNMB Rank	Worst Weighted Regret	LWWR Rank
1	14.37	7.32	41.65	1.22	16.44	1	0.18	4
4	14.34	7.21	41.54	1.46	16.38	2	0.20	6
5	14.29	7.00	42.20	0.58	16.37	3	0.09	1
6	14.39	7.00	41.87	0.61	16.37	4	0.15	2
10	14.34	6.77	42.43	0.31	16.36	5	0.16	3
7	14.37	7.21	41.26	0.94	16.33	6	0.25	8
2	14.34	6.67	42.43	0.08	16.32	7	0.19	5
12	14.34	6.57	42.43	0.09	16.29	8	0.22	7
9	14.24	6.95	41.19	1.12	16.18	9	0.26	9
11	14.07	5.90	42.43	-0.41	15.94	10	0.41	10
8	14.07	5.83	42.43	-0.65	15.91	11	0.43	11
3	14.05	5.72	42.72	-0.97	15.91	12	0.47	12

[14] Given the scale of the reduction in net market benefits in CDP13, it has not been modelled for this sensitivity analysis.

Table 59 highlights how CDP rankings change as a result of the higher discount rate. Overall, CDPs that proceed with fewer augmentations with an actionable timing are generally favoured, compared to those that include more actionable augmentations.

Table 59 Comparison of CDP rankings – 10% discount rate sensitivity and base

CDP Number	Base assumptions		10% discount rate	
	WNMB Rank	LWWR Rank	WNMB Rank	LWWR Rank
1	6	6	1	4
2	3	2	7	5
3	11	11	12	12
4	8	8	2	6
5	4	4	3	1
6	5	5	4	2
7	7	10	6	8
8	10	9	11	11
9	12	12	9	9
10	1	1	5	3
11	9	7	10	10
12	2	3	8	7

The key insights from this analysis are:

- Even with a higher discount rate, on both a weighted net market benefit and LWWR basis, New England REZ Transmission Link and Sydney Ring actionable augmentations are preferred compared to a CDP with no actionable timings (CDP9) or with either as actionable (CDP4 and CDP7).
- The best performing CDP in terms of LWWR is CDP5, which includes an actionable Marinus Link timing. The difference in rankings is due to the relatively high regret associated with not having an actionable Marinus Link in the *Hydrogen Superpower* scenario, even applying a higher discount rate.
- CDP10, which includes both an actionable Marinus Link and VNI West as a staged actionable project is now ranked fifth instead of first under weighted net market benefits, and third under LWWR. The higher discount rate increases the relative cost of project staging via early works (as these early works costs are incurred now rather than later). As a result, the additional flexibility provided by early works is less valuable in this sensitivity than with the base discount rate assumption. Compared to progressing VNI West now, proceeding with a staged actionable project now increases net market benefits by $40 million (on a net weighted market benefits). Compared to taking no action now, the staged actionable project reduces net market benefits by $20 million.
- CDP2, which makes the VNI West project actionable (with no staging) falls in ranking from third/second under weighted net market benefits / LWWR to seventh and fifth respectively.
- CDPs that progress HumeLink now (with or without staging) fall more significantly in ranking under the high discount rate. Comparing CDP11 and CDP10, applying the high discount rate leads to a reduction of $130 million in net market benefits if HumeLink was progressed now for 2026-27 rather than later.

Applying a 7.5% discount rate

Further sensitivity analysis was undertaken to explore the impact of a 7.5% discount rate on those projects which were affected by the 10% discount rate: Marinus Link, VNI West (both the full project and staged) and HumeLink (both the full project and staged). Table 60 shows the impact of the 7.5% discount rate on the ranking of a selection of CDPs that explore the benefits of these projects. Rankings are all relative to the subset of CDPs modelled.

Table 60 Comparison of CDP rankings – 7.5% discount rate sensitivity and base (rankings within subset)

CDP Number	Base assumptions		7.5% discount rate		10% discount rate	
	WNMB Rank	LWWR Rank	WNMB Rank	LWWR Rank	WNMB Rank	LWWR Rank
1	5	5	1	3	1	3
2	3	2	4	4	4	4
5	4	4	3	1	2	1
8	7	7	7	7	7	7
10	1	1	2	2	3	2
11	6	6	6	6	6	6
12	2	3	5	5	5	5

This analysis shows that:

- On a LWWR basis, rankings do not change between a 7.5% and 10% discount rate. CDP5 is highest ranked, followed by CDP10 in both sensitivities.
- CDP10 is now the second highest ranked on a weighted net market benefit basis, though weighted net market benefits are only $10 million lower than the highest ranked CDP1. As above, the relatively higher cost of early works with a higher discount rate reduces the benefits of the flexibility they provide. CDP10 is higher ranked than CDP1 on a LWWR basis.
- CDP12 (with both VNI West and HumeLink as staged actionable projects) has a lower rank under both higher discount rate sensitivities, as the relatively more expensive early works costs ultimately reduce the weighted net market benefits of this CDP in these sensitivities. The probability of a two-year delay due to schedule slippage would need to increase to 36% (from 10% in the base assumptions) for the impact of a staged HumeLink on net market benefits to be neutral when applying a 7.5% discount rate.

A6.7.3 Sensitivity to higher DER uptake

AEMO has also explored a sensitivity on the *Step Change* scenario that explores the impact of higher DER uptake, informed by the latest forecast from the Clean Energy Regulator (CER)[15]. In this sensitivity, distributed PV uptake was adjusted by the factors presented in Table 61, which overall increases the contribution of PV in New South Wales and Queensland, and reduces it in Victoria, Tasmania (until 2025) and to a lesser extent in South Australia (from 2024 onwards).

[15] See http://www.cleanenergyregulator.gov.au/RET/Scheme-participants-and-industry/the-small-scale-technology-percentage/small-scale-technology-percentage-modelling-reports.

From 2026 onwards, these adjustments effectively result in lower operational demand in New South Wales, Queensland and Tasmania, and higher operational demand in Victoria and South Australia. Across the NEM, this results in an increase in distributed PV of approximately 6%.

Table 61 Distributed PV uptake adjustment factors, relative to the base assumptions

	2021-22	2022-23	2023-24	2024-25	2025-26 onwards
NSW	1.041	1.055	1.077	1.106	1.138
QLD	1.026	1.045	1.068	1.074	1.075
SA	1.017	1.009	0.994	0.995	0.992
TAS	0.948	0.924	0.944	0.967	1.003
VIC	0.996	0.991	0.985	0.972	0.960

Table 62 presents the impact of the DER adjustment in the *Step Change* scenario, and its impact on the ranking of CDPs[16] under both ranking methodologies. Lower operational demands due to higher DER reduce the net market benefits of each CDP due to a reduced need for generation investment generally, given that the cost of the additional DER investments are not considered. Overall rankings under both methods are very robust to these changes.

Table 62 CDP performance under the Base DER and high DER sensitivity ($ billion)

CDP number	Base			High DER		
	Step Change	WNMB rank	LWWR rank	*Step Change*	WNMB rank	LWWR rank
1	25.50	6	6	24.06	6	6
2	25.59	3	2	24.13	3	2
3	25.34	11	11	23.91	11	11
4	25.41	8	8	24.03	8	8
5	25.51	4	4	24.07	4	4
6	25.59	5	5	24.15	5	5
7	25.49	7	10	24.07	7	10
8	25.39	10	9	23.97	10	9
9	25.28	12	12	23.88	12	12
10	25.59	1	1	24.13	1	1
11	25.39	9	7	23.97	9	7
12	25.59	2	3	24.13	2	3

A6.7.4 Comparing *Strong Electrification* to the *Hydrogen Superpower* scenario

AEMO has also modelled a *Strong Electrification* sensitivity, as a potential alternative to the *Hydrogen Superpower* scenario that assumes the same emissions reduction objectives, but where hydrogen uptake is more limited and energy efficiency is also more muted. This means emission reductions have to be achieved through increased electrification of the energy system. The sensitivity has been assumed to replace the

[16] Given the scale of the reduction in net market benefits in CDP13, it has not been modelled for this sensitivity analysis.

Hydrogen Superpower scenario with the same weighting for the purpose of understanding its impact on CDP rankings[17].

Table 63 below highlights the impact that the inclusion of a strong electrification sensitivity (in lieu of the *Hydrogen Superpower* scenario) has in both weighted net market benefits and least-worst weighted regrets.

Results are relatively robust to this sensitivity, as the ranking of the higher ranked CDPs does not change between the Strong Electrification and *Hydrogen Superpower* scenario.

This suggests that it is the rapid emissions reduction ambition that is driving the differences in market benefits between the CDPs, rather than the hydrogen demand in the *Hydrogen Superpower* scenario. This is not unexpected given that the differences in the CDPs are all in the period up to 2031-32 in this scenario, at which point the demand for hydrogen is not yet at very large scale, yet the earlier retirement of coal generators necessary to achieve the carbon emissions reduction objectives support the value provided by the ISP projects.

Table 63 Comparison of CDP rankings – with *Strong Electrification* sensitivity and base

CDP Number	Base assumptions		With Strong Electrification replacing *Hydrogen Superpower*	
	WNMB rank	LWWR rank	WNMB rank	LWWR rank
1	6	6	6	6
2	3	2	3	2
3	11	11	10	10
4	8	8	7	7
5	4	4	5	4
6	5	5	4	5
7	7	10	8	11
8	10	9	11	9
9	12	12	12	12
10	1	1	1	1
11	9	7	9	8
12	2	3	2	3

A6.7.5 Testing the impact of Queensland pumped storage development

This sensitivity tested the impact of additional pumped storage developments in Queensland. The sensitivity assumed an additional gigawatt of pumped hydro capacity in 2030, and 3 GW more from 2040 onwards of deep storage. It was designed to ascertain the impact of that additional capacity on the benefits of QNI Connect. This sensitivity was only applied to the *Progressive Change* and *Step Change* scenarios.

This additional storage enables more utility-scale solar PV investments, and reduces the need for utility-scale shallow storages, wind and gas generation that would otherwise be required in the base case.

Table 64 highlights the net market benefits of the QNI Connect augmentation with the base assumptions and in this sensitivity, retaining the optimal timing from the base case. Although not at an actionable timing, QNI

[17] Given the scale of the reduction in net market benefits in CDP13, it has not been modelled for this sensitivity analysis.

Connect results in significant benefits in the early to late 2030s, depending on the scenario. As a result of the additional storage, the value of the QNI Connect augmentation is marginally reduced by around $10 million in *Progressive Change* and increases by around $60 million in *Step Change*. These impacts suggest that the benefits of a QNI Connect augmentation are robust to additional firm generation being added in Queensland.

Table 64 Net market benefits of QNI (NPV, $ billion) in the Base and additional Queensland storage sensitivity

	Progressive Change	*Step Change*
Base	0.81	1.27
Additional Queensland storage	0.80	1.33
Change in net market benefits	-0.01	0.06