Appendix 6. Cost benefit analysis

June 2022

Appendix to 2022 ISP for the National Electricity Market

Important notice

Purpose

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

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

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Version control

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

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ISP Appendices

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A6.1 Introduction

Section 6 of the 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]. This 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: Explains how updated inputs since the Draft ISP have been used to inform the determination of the ODP.
- A6.4: Steps through the process and outcomes of the determination of the least-cost development path in each scenario.
- A6.5: Outlines the set of CDPs which have been developed based on the least-cost development paths.
- A6.6: Provides a detailed assessment of these candidates.
- A6.7: Explores the risks and benefits of actionable project timings.
- A6.8: Tests the resilience of the CDPs to several sensitivities.
- A6.9: Considers the potential distributional effects of alternative transmission developments.

In this appendix, all dates are 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 **ISP 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.

A6.2 Approach to the cost benefit analysis

A6.2.1 The ISP approach to cost benefit analysis

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

- Setting out the principles that govern the CBA.
- 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 ODP through sensitivity analysis.

The key terminology used throughout this section is as follows:

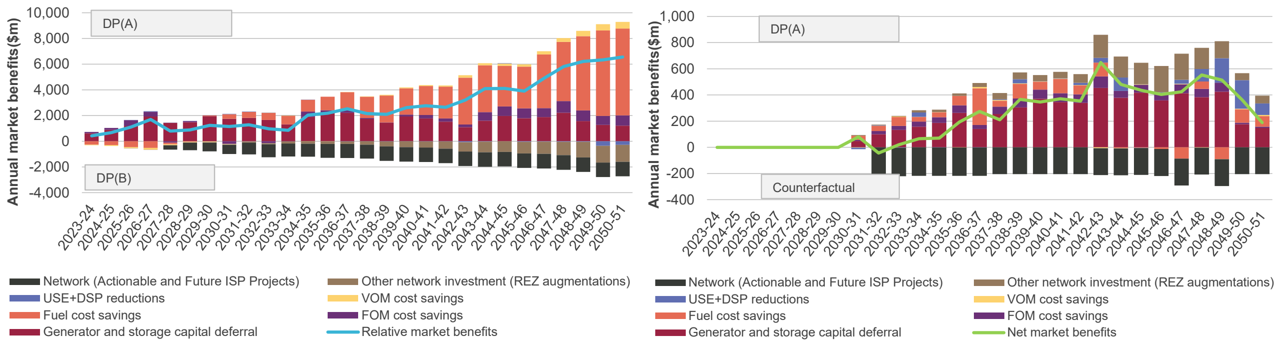
- The **earliest in-service date (EISD)** of a project is the earliest date the project can be completed (including commissioning and interregional testing as appropriate).
- **Actionable projects** are identified where the CBA has concluded that the project should proceed at the EISD (or EISD + 1 given the two-year cycle of the ISP).
  - **Actionable ISP projects** should progress under the RIT-T. These projects require a Project Assessment Draft Report (PADR) to be completed within 24 months of the ISP publication (unless the PADR is already completed).
  - **Actionable NSW projects** will progress through under the *Electricity Infrastructure Investment Act 2020* (NSW) rather than through the RIT-T. For the purposes of this appendix, all actionable projects are treated equally, irrespective of the subsequent delivery approach – under the actionable ISP or actionable NSW framework.
- **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

This 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



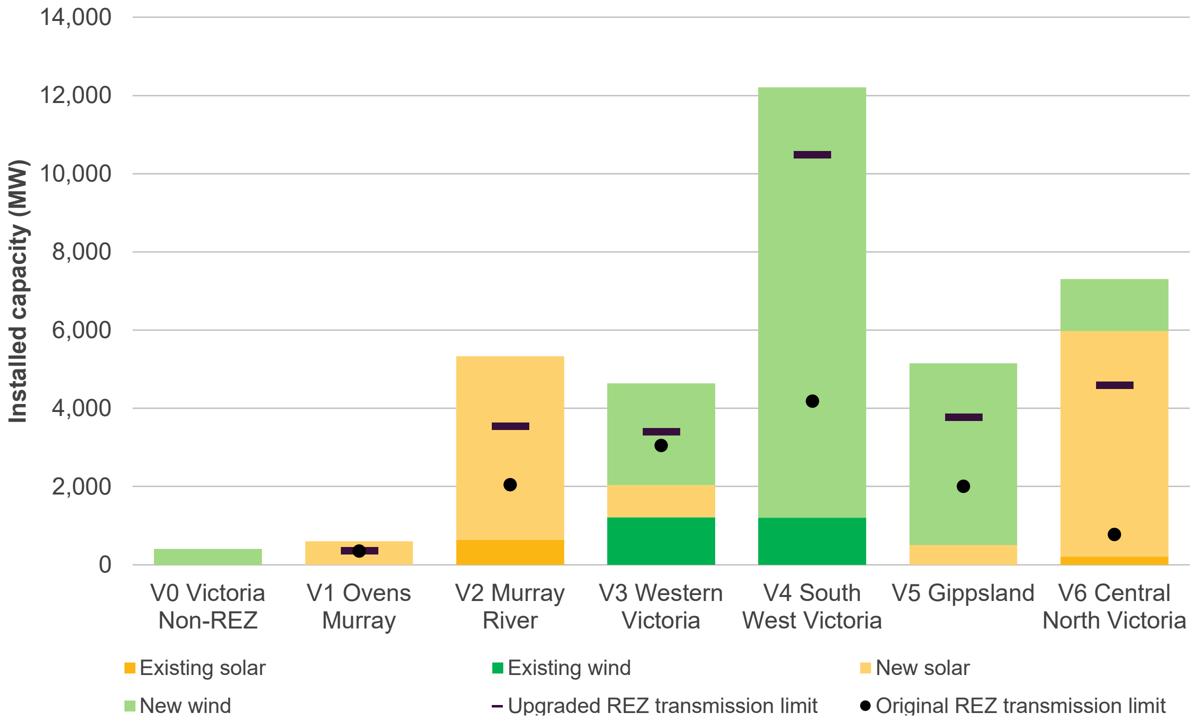
Interpreting Figure 1:

- 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 DP 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 existing 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[3] 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.

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

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

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 use 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 *Progressive Change*, as per the *ISP Methodology*, which states that revenue adequacy modelling would be used in scenarios that do not have explicit carbon budgets. This approach is further clarified in AEMO's *Addendum to the Draft 2022 ISP*[4]; this approach has not changed in the modelling performed to finalise the 2022 ISP.

Where it has been deemed potentially material, AEMO has used time-sequential modelling to support the comparison of key CDPs, focusing on *Step Change* and *Progressive Change*. Where these benefits have been quantified, the horizon has been limited to the first 10 years after the commissioning of the first potential actionable 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 a comparison of the CDPs, additional reliability cost savings are determined by comparing USE between DPs, with any difference in USE valued at the value of customer reliability. In these instances, any reliability cost savings that are present in the capacity outlook

[4] Available at https://aemo.com.au/-/media/files/major-publications/isp/2022/addendum/addendum-to-the-draft-2022-isp.pdf.

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 these additional reliability cost savings.

Competition benefits

For a small subset of CDPs, indicative competition benefits have been presented for information only[5]. 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*[6].

Any total system cost and net market benefits provided in this appendix, or in the main report, exclude these additional benefits. Any indicative competition benefits provided are based on modelling from the Draft ISP.

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

Distributional effects

For a selection of CDPs, AEMO has presented information on indicative distributional effects for NEM consumers in Section A6.9. Distributional effects consider the distribution of costs and market benefits of a CDP. As considerations on wealth transfer and equity issues are not included in the CBA framework, distributional effects are presented for information purposes only.

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 distributional effects.

[5] 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.

[6] 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 Sensitivity to recent input changes

A6.3.1 Approach to developing the assessment of the ODP between the Draft and final ISP

The Draft 2022 ISP provided an extensive implementation of the approach to developing and comparing CDPs, with Appendix 6 that accompanied the Draft 2022 ISP providing the quantitative outcomes to support the determination of the Draft ODP. For the final ISP, the outcomes of this process from the Draft have been retained on the basis that the analysis and process remain sound, as demonstrated by the impact of updated assumptions on the relativity between CDPs presented in this section. As such, much of the material in this Appendix is unchanged.

However, since December 2021 there have been a number of changes in market conditions, and AEMO received extensive stakeholder feedback on the Draft ISP. As a result, this Appendix has been expanded to include additional sensitivities (for example, the inclusion of the Victorian Government's ambition for offshore wind development) and to consider the impact of updated assumptions (most notably, the earlier retirements of the Eraring, Loy Yang A and Bayswater power stations announced after the Draft 2022 ISP was published).

This additional analysis on updated inputs has focused on understanding the impact on the costs and benefits associated with three strategic, actionable projects that were recommended in the Draft ODP: HumeLink, Marinus Link and VNI West. The analysis has been expanded to consider other factors which are relevant to determining the ODP, the details of which are documented in the 2022 ISP's main report.

The additional analysis has largely focused on *Step Change* as the most likely scenario but includes all scenarios where required for specific CDP comparisons.

A6.3.2 Summary of updated input assumptions

To understand the impact of announcements and developments in the NEM since the Draft 2022 ISP publication in December 2021, AEMO has conducted additional modelling which applies recent input changes, including the following key changes:

- Implemented the 2025 retirement date for Eraring, and early expected closure years for Bayswater and Loy Yang A (see Section 4.2.7 of Appendix 4 for further detail).
- Delayed the earliest entry date of Marinus Link by two years, as advised by TasNetworks (this advice was footnoted in the Draft ISP, but was not considered in the Draft ISP cost benefit analysis).
- Updated committed and anticipated projects to reflect AEMO's February 2022 update of the Generation Information page.
- Minor adjustments and improvements in transmission limit and REZ assumptions based on TNSP feedback to the Draft ISP.
- Enhanced electrolyser capacity expansion modelling approach based on stakeholder feedback to the Draft ISP.

The impact of these changes on the general development of generation and storage is described in Section A2.3 of Appendix 2.

A6.3.3 Impact on the rankings of CDPs in Step Change

To explore the impact of recent input changes on net market benefits and CDP rankings, a selection of CDPs were re-modelled for *Step Change* and compared to the original Draft ISP outcomes, focusing on those CDPs which provide information on the costs and benefits of actionable projects. Additional scenarios were modelled for some CDPs, particularly those that inform further analysis for HumeLink (further details provided later in this section and in Section A6.7.3). The comparison of relative CDP rankings in *Step Change* is shown in Table 2 below. Details of the CDPs are provided in Table 19.

Table 2 CDP performance under the Draft ISP and updated inputs – *Step Change* only (net market benefits, $ million)

CDP number	Draft ISP			Recent input changes		
	Step Change	NMB rank	NMB relative to optimal	*Step Change*	NMB rank	NMB relative to optimal
2	$25,594	1	-	$24,478	1	-
5	$25,510	5	-$83	$24,453	4	-$26
6	$25,586	4	-$8	$24,392	5	-$86
8	$25,393	6	-$201	$24,295	6	-$183
9	$25,278	8	-$316	$24,023	8	-$455
10	$25,594	1	-	$24,478	1	-
11	$25,393	6	-$201	$24,295	6	-$183
12	$25,594	1	-	$24,478	1	-

NMB = Net Market Benefits

The CDP rankings are relatively robust to the recent input changes; CDP2, CDP10 and CDP12 remain the highest ranking CDPs. There are a number of other changes evident in the relative benefits when comparing CDPs:

- CDP6 relative to CDP2 has a larger net market benefit reduction under the updated inputs, which shows an actionable Marinus Link being more valuable, mostly due to the updated EISD (that is two years later than previously assumed) being better aligned with the timing of when the project provides positive benefits.
- CDP11 relative to CDP12 shows that the net cost of proceeding with an un-staged, actionable HumeLink has reduced.
- CDP5 relative to CDP2 has a lower net market benefit reduction under the updated inputs of $58 million, showing that an un-staged, actionable VNI West timing is slightly less valuable, although still beneficial at its actionable timing in *Step Change*.

A6.3.4 Articulating the change in net market benefits relative to the counterfactual from the Draft ISP

CDP12, as the ODP in the Draft 2022 ISP, was re-modelled across all scenarios to demonstrate the impact of updated inputs on the net market benefits relative to a counterfactual DP, as summarised in Table 3 below.

Table 3 Comparing CDP12 and Counterfactual under Draft ISP assumptions and updated inputs (net market benefits, $ billion)

	Step Change	*Progressive Change*	*Hydrogen Superpower*	*Slow Change*	Weighted
Draft ODP (CDP12)	25.59	16.20	70.20	3.35	29.56
Updated inputs (CDP12)	24.48	15.10	64.59	3.53	27.74
Impact of updated inputs on net market benefits	-1.12	-1.10	-5.61	0.17	-1.82

The updated inputs resulted in changes to CDP12's net market benefits across all scenarios, with the key reasons elaborated below:

- **Common across all scenarios:**
  - Refined input assumptions were applied to represent potential network losses more accurately in Northern Queensland. This update was based on TNSP feedback to capture more realistically the implications of future REZ expansion in this area on network losses. This redistribution of VRE investments resulted in the need for fewer REZ augmentations elsewhere, and reduced the total cost of transmission investment associated with REZ developments in the NEM.
  - Other minor adjustments to assumptions for other REZs in response to stakeholder submissions to the Draft 2022 ISP reduced the overall cost of investment in REZ augmentations. This effect is mostly evident in the later years of the horizon.
- ***Hydrogen Superpower*:**
  - As a result of stakeholder submissions to the Draft 2022 ISP, enhancements to the electrolyser capacity expansion modelling approach resulted in less storage development towards the end of the modelling horizon[7]. This reduced the costs for the *Hydrogen Superpower* counterfactual DP, more than it did in CDP12, lowering the net market benefit for this scenario.

Although the other input updates documented in Section A6.3.2 are material for the comparison between some CDPs, they are not significant drivers of the change in net market benefits relative to the counterfactual DP.

Exploring the impact on net market benefits relative to TOOTs for the strategic, actionable projects

A "TOOT" (Take-one-out-at-a-time) refers to a DP where an augmentation has been removed entirely. It provides an indication of the net market benefits of a project over the entire modelling horizon.

Table 4 presents the impact of recent input changes on the long-term benefits of the strategic, actionable projects demonstrated through the TOOT analysis, where CDP12 is compared against DPs where a certain actionable project (including any augmentations along the project route) is completely removed.

[7] Further detail is provided in Section A2.3.3 of Appendix 2.

Table 4 TOOT comparisons for strategic, actionable projects under *Step Change* (Net market benefits, $ billion)

	Marinus Link	*VNI West*	*HumeLink*
Draft ISP assumptions	4.80	1.88	1.30
Updated inputs	4.51	1.82	1.34
Impact of updated inputs on net market benefits	-0.29	-0.06	0.04

TOOT comparisons show the net market benefits of these strategic, actionable projects changing slightly with recent input updates, but there has been no fundamental change to the long-term net market benefits provided by these critical projects. Further detail on these projects, including the impact of updated inputs and assumptions, is provided in Section A6.7.

A6.4 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 was as follows:

- The results of the Single-Stage Long-Term Model[8] (SSLT) were used to inform which transmission flow paths are likely to benefit from augmentation, as well as an indication of timing and scale.
- Based on the indicative transmission developments provided by the SSLT model, many DPs were simulated which test whether any of the available flow path augmentation options deliver positive net market benefits.
- These various augmentation options were 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 were then tested around this point to determine which is an optimal timing.
- This process was 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 were included to confirm that they do not provide any further increase in net market benefits.

The details in this section present a 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 depth the potential early timings of potential actionable projects. These are explored in more detail through the assessment of CDPs in Sections A6.6 and A6.7.

This section remains unchanged from the Draft ISP and is the foundation for subsequent analysis in the final ISP.

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

Table 5 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).

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

- The magnitude of market benefits delivered by both stages of Marinus Link (DP3).
- The benefits provided by a timely HumeLink delivery (DP4).

Table 5 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

* Note that the determination of the least-cost DPs has been retained from the Draft ISP and therefore maintains the original earliest timings for the Marinus Link cables for the purposes of this table. As discussed in the main 2022 ISP report, the project's delivery is now expected to be 2029-30 and 2031-32.

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

Comparing options for the VNI West development

Alternative DP1 explores the benefits of choosing a different 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 6 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.

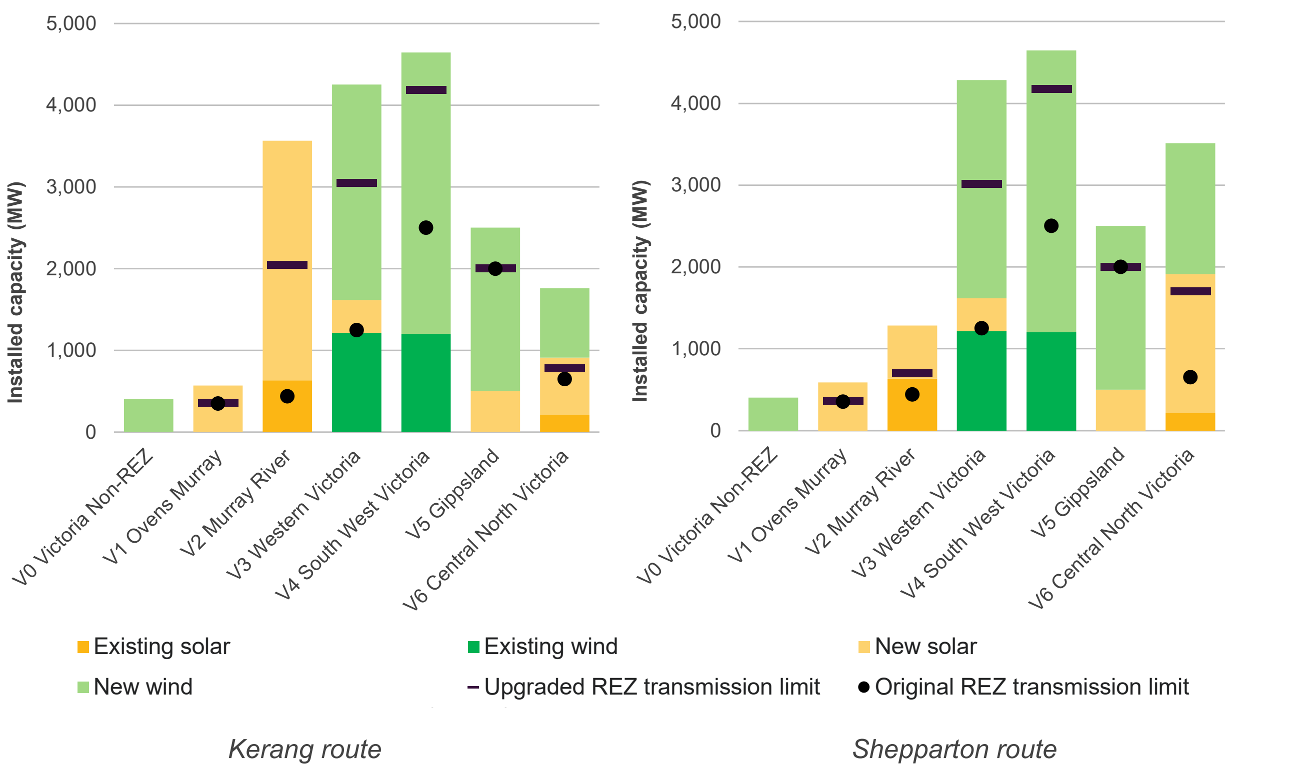
These savings come with having access to the better renewable resource in Murray River compared to Central North Victoria, and the additional hosting capacity provided being greater in magnitude, meaning less is spent on building generation capacity and augmenting other REZs to meet demand.

Table 6 Relative benefits of the least-cost DP by category compared to Alternative DP1 with VNI West (via Shepparton), *Step Change*

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 [left] compared to Shepparton route [right]), *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-fired 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 7.

Table 7 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 A6.6.2.

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 8 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 A6.6.2 provides more detail on the benefits HumeLink provides in *Step Change.*

Table 8 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 beyond committed and anticipated developments, as explained in Appendix 2. Table 9 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 9 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

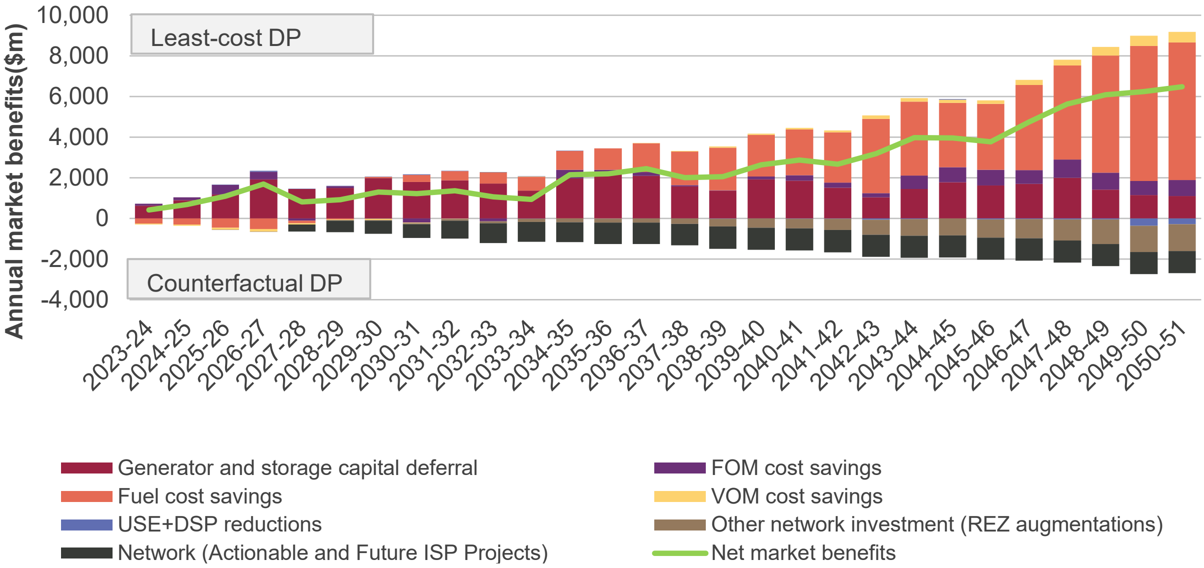
Class of market benefit	Net benefit (NPV, $ million)
Gross market benefits	37,757
Network (Actionable and Future ISP Projects)	-8,686
Other Network investment (REZ augmentations)	-3,477
Total net market benefits	25,594

Figure 4 presents the annual net market benefits of the least-cost DP in *Step Change*. 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-fired generation development, including Combined Cycle Gas Turbines (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 without transmission investment. Further comparisons of the capacity development and generation outcomes are provided in Appendix 2.

The net market benefits within each scenario are considerably higher than those provided in the 2020 ISP when compared against corresponding scenarios. This is primarily due to the extended modelling horizon and the higher demand, primarily due to the impact of electrification.

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



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

Table 10 presents the ISP project timings in the least-cost DP for *Progressive Change* with a subset of Alternative DPs. The sample of Alternative DPs selected below demonstrate:

- Why QNI Connect is a future project in *Progressive Change*, 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 10 Examples of developments paths assessed in *Progressive Change*

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 2021 IASR, 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.

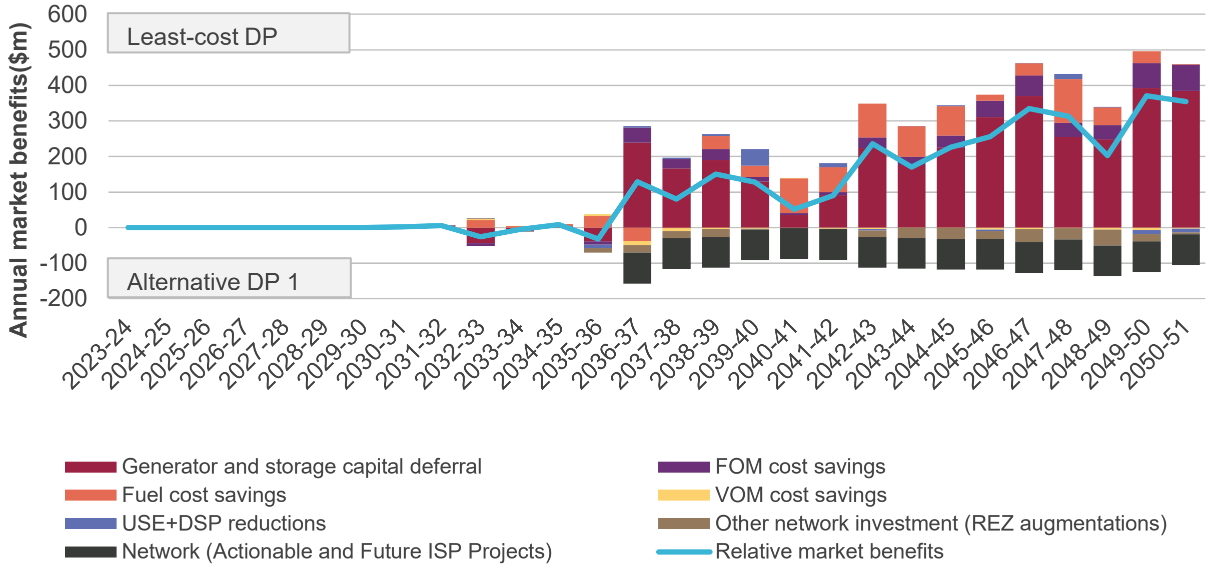
The benefits of strengthening interconnection between Queensland and New South Wales

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.

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.

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

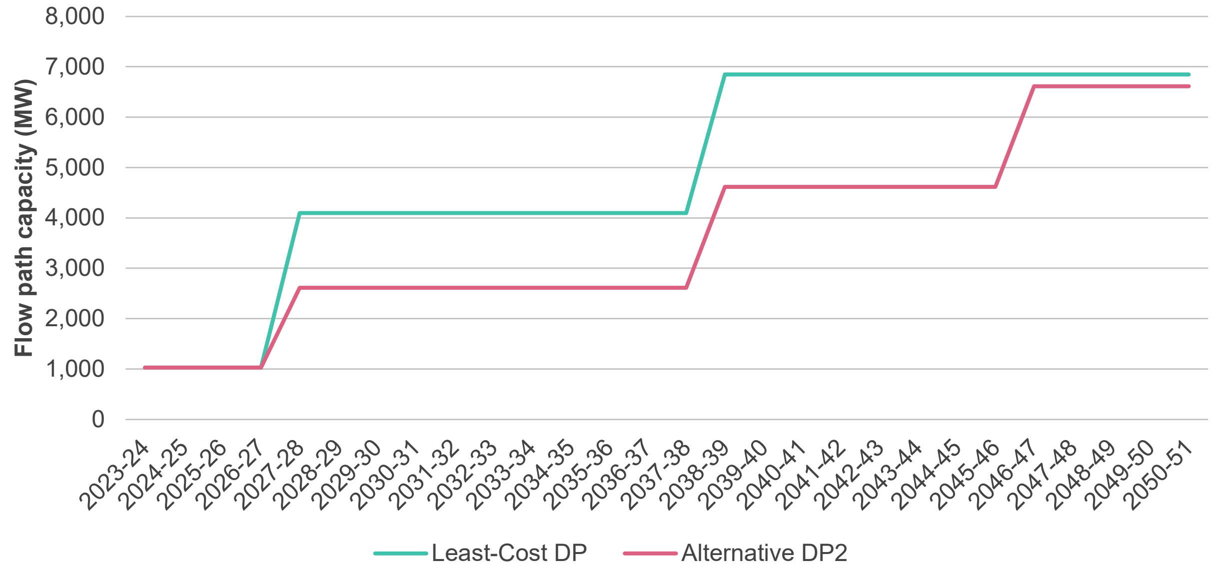


Long-term value provided by 500 kV augmentation to New England

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[9]).

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

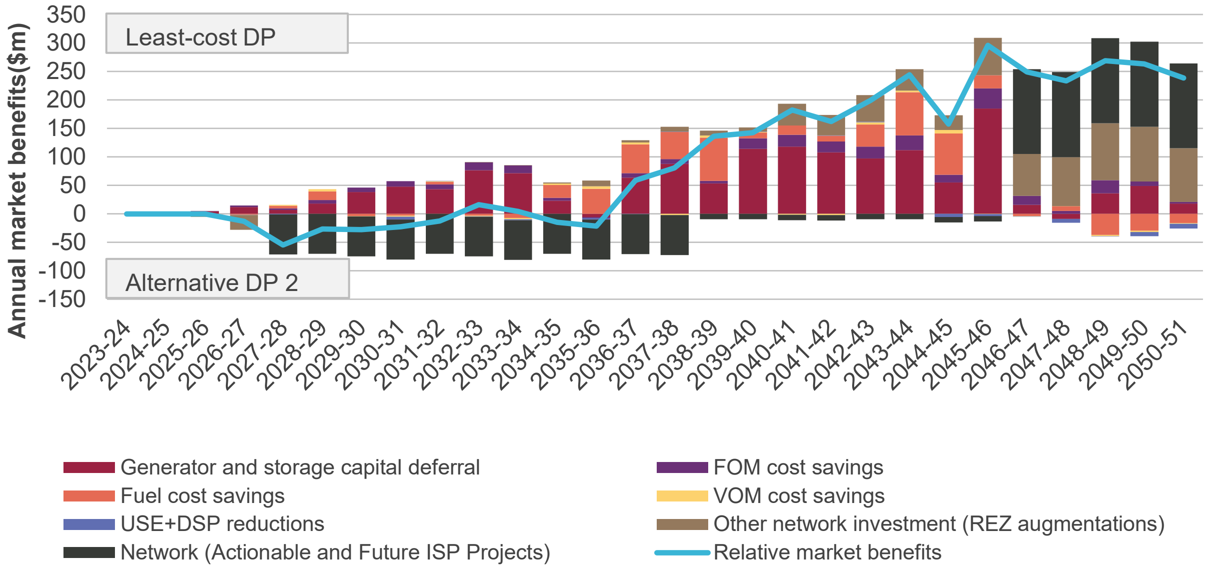


[9] Further details can be found in the "Augmentation options" tab in the Inputs and Assumptions workbook that accompanies the IASR, at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

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 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.

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 A6.4.1, and explored in further detail in Section A6.6.2. The classes of market benefits attributable to the optimal HumeLink timing in *Progressive Change* are provided in Table 11. These results reinforce that HumeLink is beneficial in all scenarios.

Table 11 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 12 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 *Progressive Change* least-cost DP, as shown in Table 12.

Table 12 Net market benefits of the least-cost development path by category, *Progressive Change* (NPV)

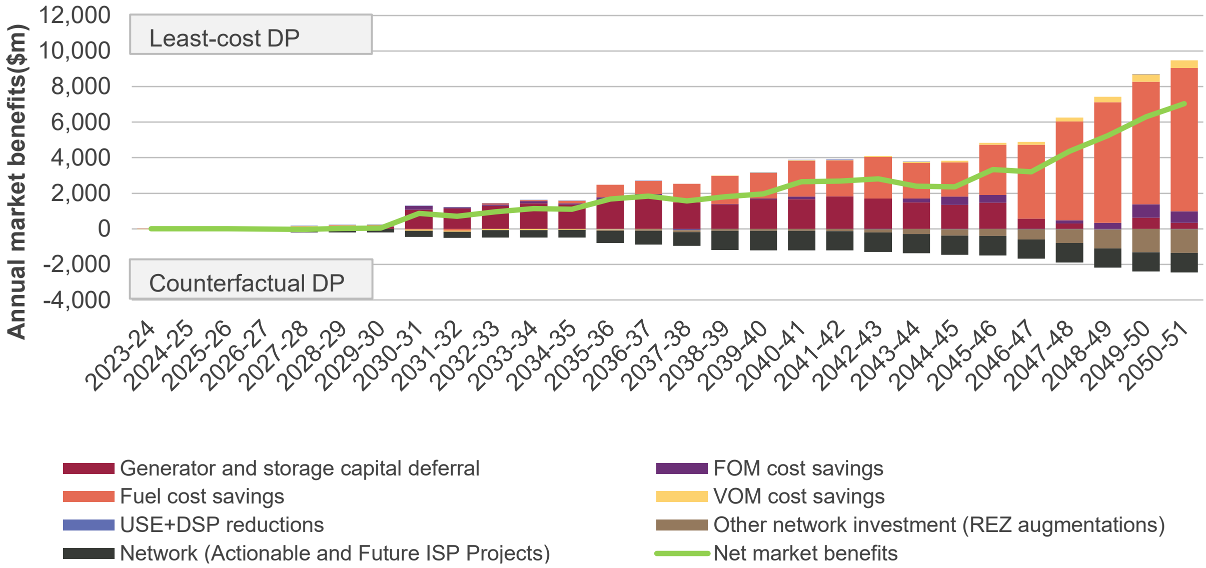
Class of market benefit	Net benefit ($ million)
Generator and storage capital deferral	10,070
FOM cost savings	1,233
Fuel cost savings	13,211
VOM cost savings	274
USE+DSP reductions	16
Gross market benefits	24,804
Network (Actionable and Future ISP Projects)	-6,331
Other Network investment (REZ augmentations)	-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 A6.8.1.

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 A6.8.2 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 *Progressive Change*



A6.4.3 Least-cost development path for *Hydrogen Superpower*

The least-cost DP in *Hydrogen Superpower* and two alternative options are presented in Table 13.

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).

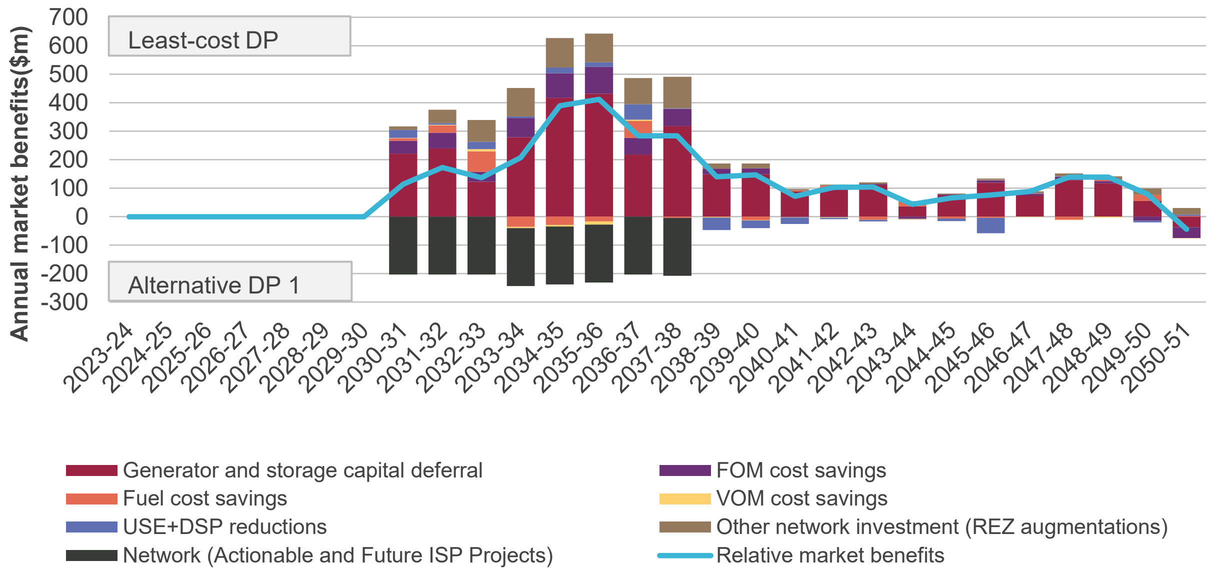
Table 13 Examples of development paths for *Hydrogen Superpower*

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 *Hydrogen Superpower*



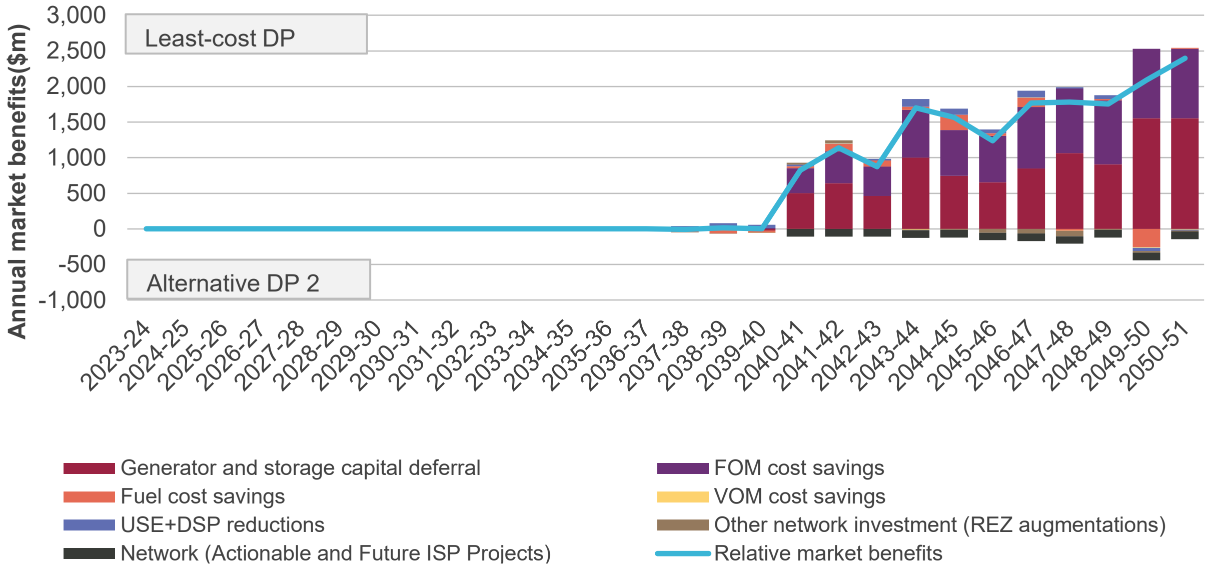
The total relative market benefit reduction of $1.3 billion is due to capital deferral and FOM cost savings. With VNI West at an earlier timing, there are comparatively fewer investments in new large-scale storage and VRE needed in Victoria, which results in substantial cost savings.

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 *Hydrogen Superpower*. 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 *Hydrogen Superpower*



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 *Hydrogen Superpower*

Table 14 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.

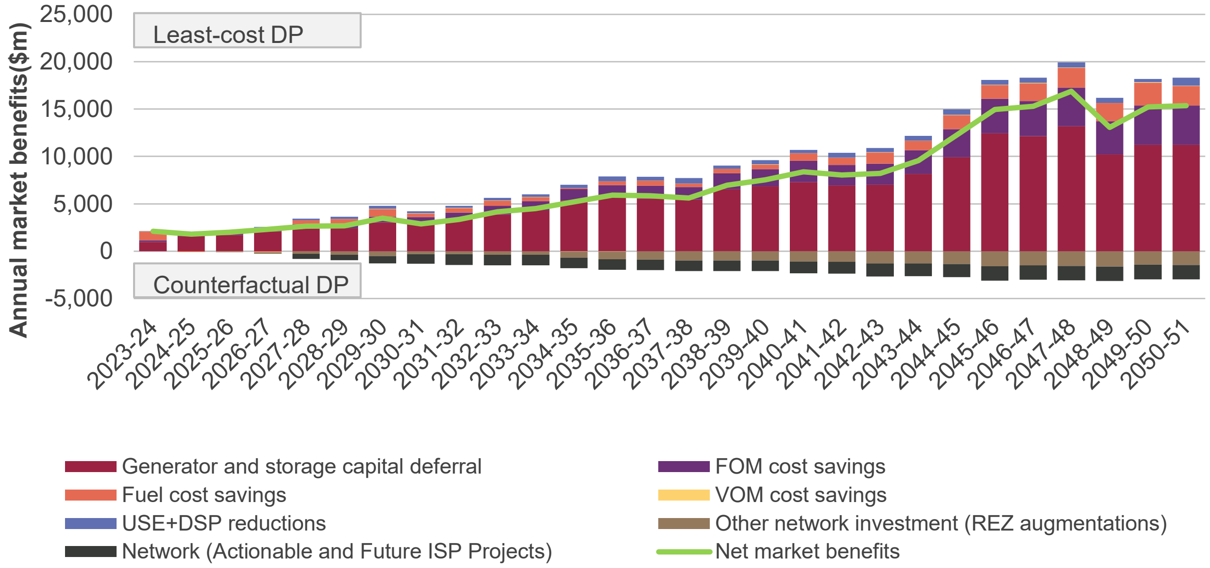
Table 14 Net market benefits by class of the least-cost development path by category, *Hydrogen Superpower*

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 *Hydrogen Superpower*



Hydrogen Superpower is modelled for the first time in this 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.

A6.4.4 Least-cost development path for *Slow Change*

The least-cost DP for *Slow Change* and alternative options are presented in Table 15. 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:

- 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 15 Examples of development paths for *Slow Change*

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	-420

The Alternative DP1 assesses the impact of developing Sydney Ring reinforcement earlier than in the least-cost DP for *Slow Change*. The relative benefit of the least-cost DP compared to DP1 is shown in Table 16 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 *Slow Change*. 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 *Slow Change*.

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

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 *Slow Change*

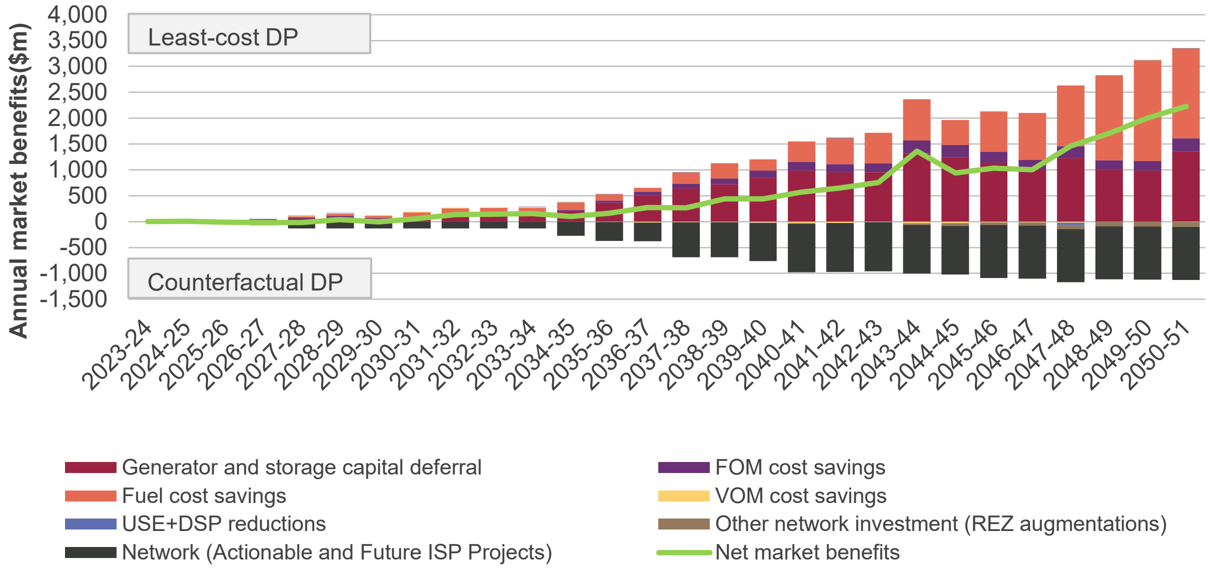
Table 17 provides a summary of the total net market benefits by class to 2050-51 of the least-cost DP, relative to the counterfactual. The cumulative gross benefits are $4.3 billion, far lower than in other scenarios. The benefits are primarily in generator capital and fuel cost savings.

Table 17 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-fired 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*



A6.4.5 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 *Hydrogen Superpower*, 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 18 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
Bayswater to Newcastle port augmentation	-	-	2040-41	-

Network options	*Step Change*	*Progressive Change*	*Hydrogen Superpower*	*Slow Change*
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

* Note that the determination of the least-cost DPs has been retained from the Draft ISP and therefore maintains the original earliest timings for the Marinus Link cables for the purposes of this table. As discussed in the main 2022 ISP report, the project's delivery is now expected to be 2029-30 and 2031-32.

A6.4.6 Identifying potential actionable 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: 2029-30, cable 2: 2031-32)[10].
- 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.
- QNI Connect.
- A project that facilitates power from North to Central Queensland.
- South West Victoria REZ expansion.
- Mid North South Australia REZ expansion.

[10] The Draft ISP applied earlier full commissioning date for both Marinus Link cables, and the updated first commissioning dates were tested through a sensitivity.

- New England REZ extension.
- Far North Queensland REZ expansion.
- 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.

A6.5 Determining the set of candidate development paths to assess the 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 first 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.

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 has not changed from the Draft ISP. The CDPs are shown in Table 19, which also sets out how each CDP has been developed. The purpose of each CDP will be further expanded in Section A6.6, 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 *Progressive Change* least-cost DP (CDP1) but with Marinus Link actionable.
  - CDP6 is also based on *Progressive Change* least-cost DP (CDP1) but with VNI West actionable. CDP5 and CDP6 effectively bridge the difference between CDP1 and CDP2.
  - CDP8 adds HumeLink as an actionable project to *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 *Progressive Change* least-code development path (CDP1) and provides an ability to explore the merits of the project through comparison with CDP1.
  - CDP9 delays all actionable projects entirely to (potential) future projects.
- **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 19 Candidate development paths

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

A6.6 Assessing the candidate development paths

A6.6.1 Ranking the Candidate Development Paths

The determination of the ODP is informed by assessing the performance of the CDPs across the scenarios, as well as their robustness demonstrated by sensitivity analysis (see Section A6.7.5). This section compares the various CDPs to explore the benefits and costs provided by the potential actionable projects, including their impact on each other.

Note that this section has been retained from the Draft ISP. The impact of updated assumptions has been explored in key CDPs in Section A6.3. As described in that section, the finalisation of the ISP has not re-prosecuted all CDP analysis performed in the Draft ISP, rather focusing on validating the conclusions of the Draft ISP to new information. Updates to reflect the delay to Marinus Link's EISD, for example, are not represented comprehensively in this section (but relative insights are provided in the earlier section).

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'[11] 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 20 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 20 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

[11] '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.

CDP Number	*Step Change*	*Progressive Change*	*Hydrogen Superpower*	*Slow Change*	Weighted Net Market Benefits (NMB)	WNMB Rank	Worst Weighted Regret	LWWR Rank
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

Table 20 highlights that the top-ranked CDPs all deliver over $29 billion NPV of net market benefits[12] 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 A6.7.2 and A6.7.3).

Section A6.3 showed the impact of updated inputs and assumptions on CDP rankings with a focus on *Step Change*, generally showing that the rankings were robust to the updated inputs.

The remainder of this section explores the value provided by those key projects that feature at an actionable timing in highly ranked[13] CDPs. Section A6.7 details more specific comparisons between CDPs and their relevance to how AEMO has determined the ODP, including how updated input assumptions have impacted some of these key comparisons.

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 A6.7.5 then provides an assessment of the robustness of the high ranking CDPs to sensitivity analysis.

A6.6.2 Assessing the critical projects in high ranking CDPs

The higher ranked CDPs (see Table 20) 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*[14]).
- 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*, the least-cost DP has all of these

[12] $29 billion NPV of net market benefits was identified in the Draft 2022 ISP. Updated analysis has confirmed these benefits as slightly lesser due to updated inputs, to $28 billion NPV, as described in Section A6.3.4.

[13] 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.

[14] $26 Billion NPV of net market benefits in *Step Change* was identified in the Draft 2022 ISP. Updated analysis has confirmed these benefits as slightly lesser due to updated inputs, to $24.5 Billion NPV, as described in Section A6.3.4. This applies to all the values quoted in this list.

key projects operational by 2031-32 (see Table 5). The remainder of this section illustrates the significant benefits provided by these projects, using modelling outcomes from the Draft ISP.

Section A6.7 focuses on determining the timing that optimises benefits to consumers, taking into consideration regret costs associated with over- or under-investment across scenarios, and also considering for strategic projects the impact of updated inputs and assumptions.

New England REZ transmission Link

With the annual VRE generation targets of the 2021 IIO Report[15] 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 21 shows the market benefits delivered by the project compared to a DP that removes New England augmentations entirely (referred to as a "TOOT"), which clearly demonstrates that increasing the access to the New England REZ is critical to efficient transformation of the NEM, contributing approximately $5.5 billion towards the $26 billion total net market benefits of the highest ranked CDP in *Step Change*.

Table 21 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

[15] See https://aemo.com.au/-/media/files/about_aemo/aemo-services/iio-report-2021.pdf.

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-fired 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-fired 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 *Step Change*, and Table 22 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*

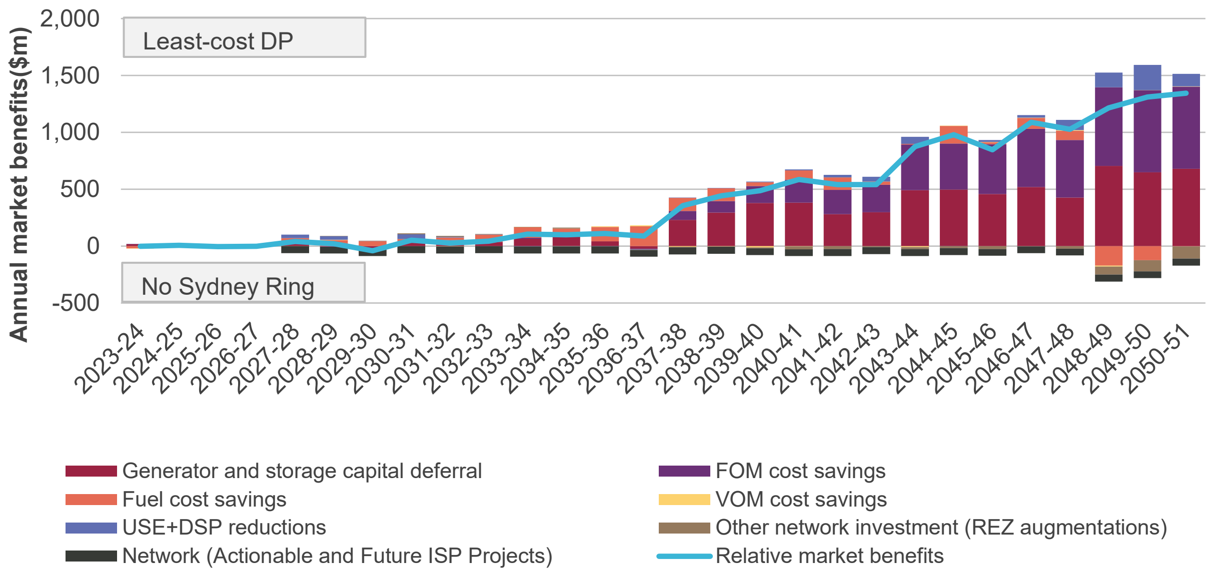


Table 22 Relative market benefits of Sydney Ring augmentation ($ billion)

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

Class of market benefit	Relative benefit (NPV, $ million) of Sydney Ring augmentation
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 23 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). Note these results are unchanged from the Draft ISP and therefore apply the timings and costs that were used in the preparation of the Draft.

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

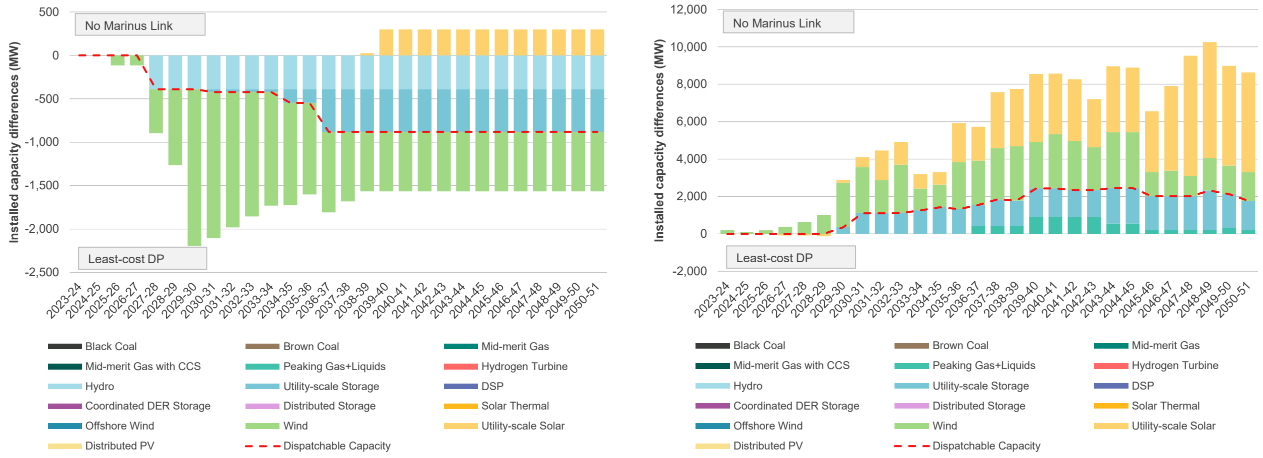
The benefits of Marinus Link are primarily accrued through savings in capital costs. Major savings in fuel and REZ augmentation costs are also provided as generation from other sources and REZs is deferred, and curtailment of Tasmanian wind is reduced.

Table 23 Market benefits provided by Marinus Link

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*



Focusing on *Step Change*, Table 24 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 24 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 25, 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 *Slow Change* 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 *Progressive Change*, depending on the individual CDPs.

Table 25 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

As outlined previously, these dates reflect the assumptions from the Draft ISP, and do not incorporate the updated Marinus Link timing confirmed after the Draft ISP modelling was completed.

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.

Table 26 shows that the second Marinus Link cable delivers net market benefits in all four scenarios. The benefits of the second Marinus cable vary between scenarios, as they are influenced by decarbonisation targets and the associated speed of thermal generation retirements, mainly in Victoria.

Table 26 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

Although the second cable does not necessarily deliver benefits immediately after its construction (particularly in *Progressive Change* and *Slow Change)*, the additional $600 million cost[16] of delivering the second cable more than three years after the first cable means that the delivery of the second cable within those three years is always beneficial. For example, as shown above, the optimal timing of the second cable in *Slow Change* is not until 2037-38. However, even when the first cable is delivered in 2027-28, a 2030-31 delivery (within three years of the first cable) results in approximately $50 million of additional net market benefits compared to a delayed delivery. In *Progressive Change*, this increase in net market benefits is over $200 million.

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 27 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.

[16] As described in Section 4 of the *Addendum to the Draft 2022 ISP*, at https://aemo.com.au/-/media/files/major-publications/isp/2022/addendum/addendum-to-the-draft-2022-isp.pdf.

Table 27 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 *Step Change* and *Progressive Change*. Furthermore, without the TRET, the optimal timing of Marinus Link would likely be delayed by up to three years in *Progressive Change*. Without the TRET, an actionable timing remains optimal for Marinus Link in *Step Change*.

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 *Step Change* 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), although additional firming capacity is still required even with VNI West.

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

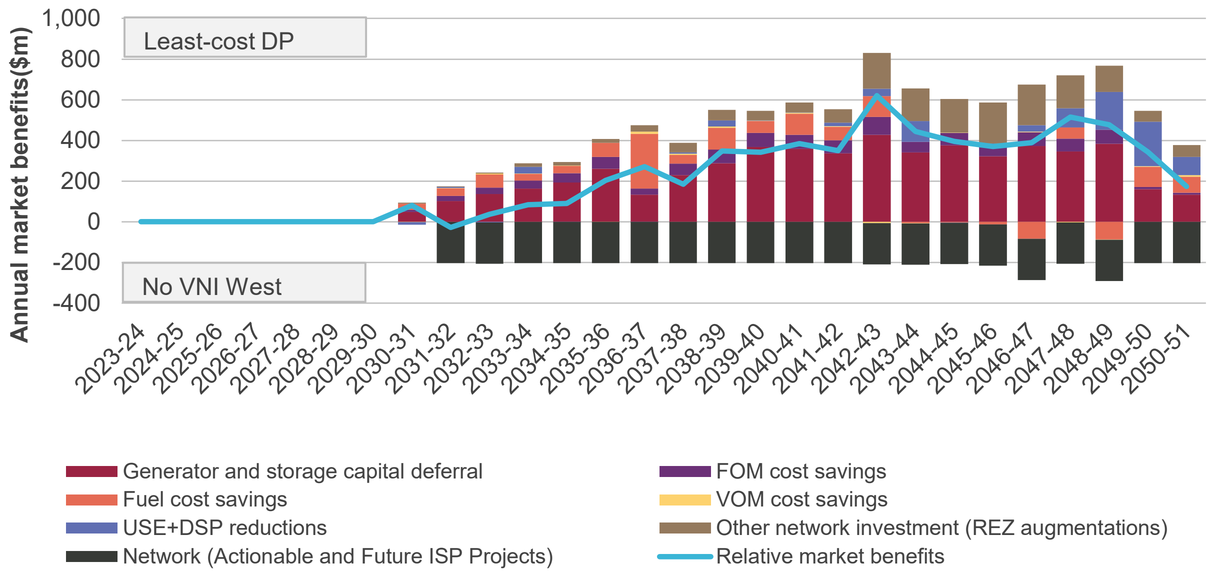
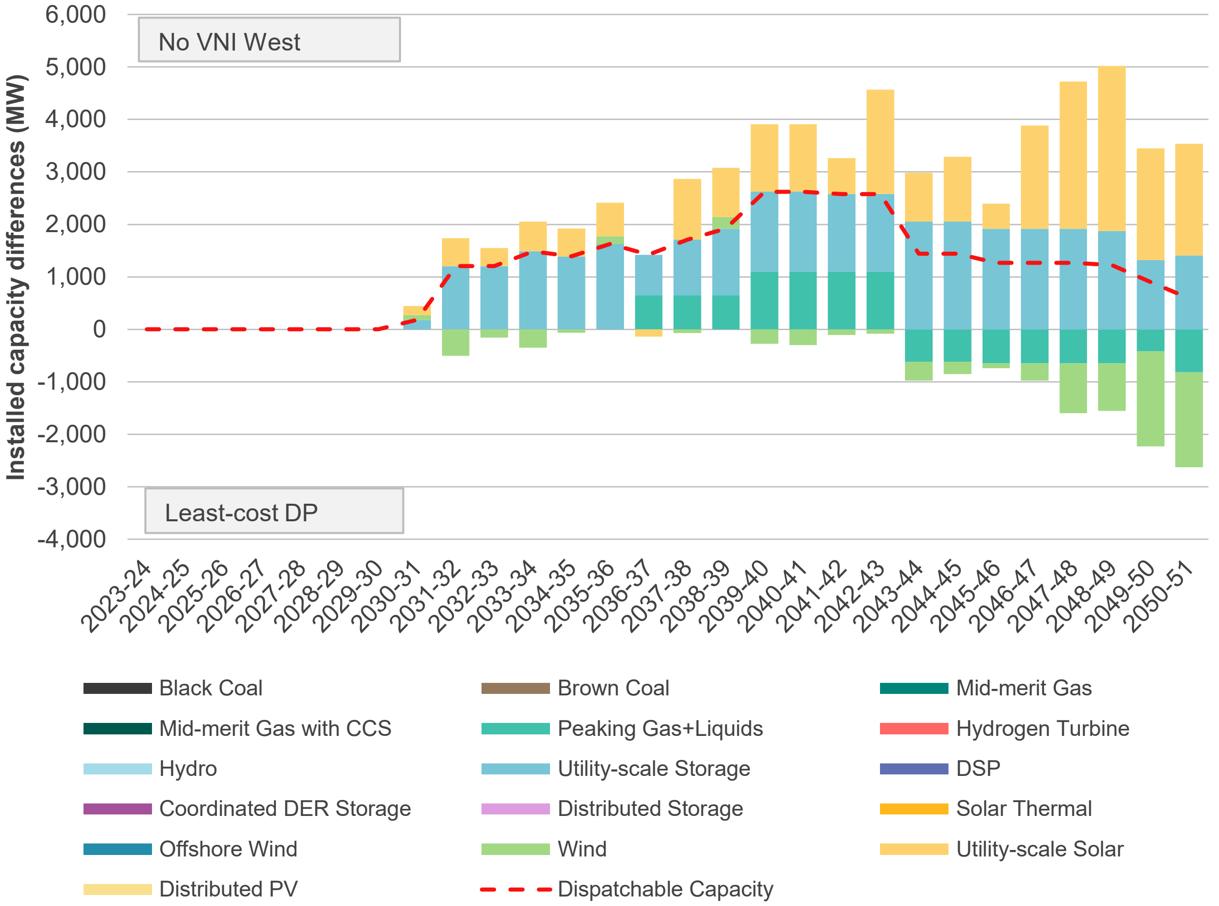


Figure 16 Differences in generation and storage capacity built with and without VNI West – *Step Change*

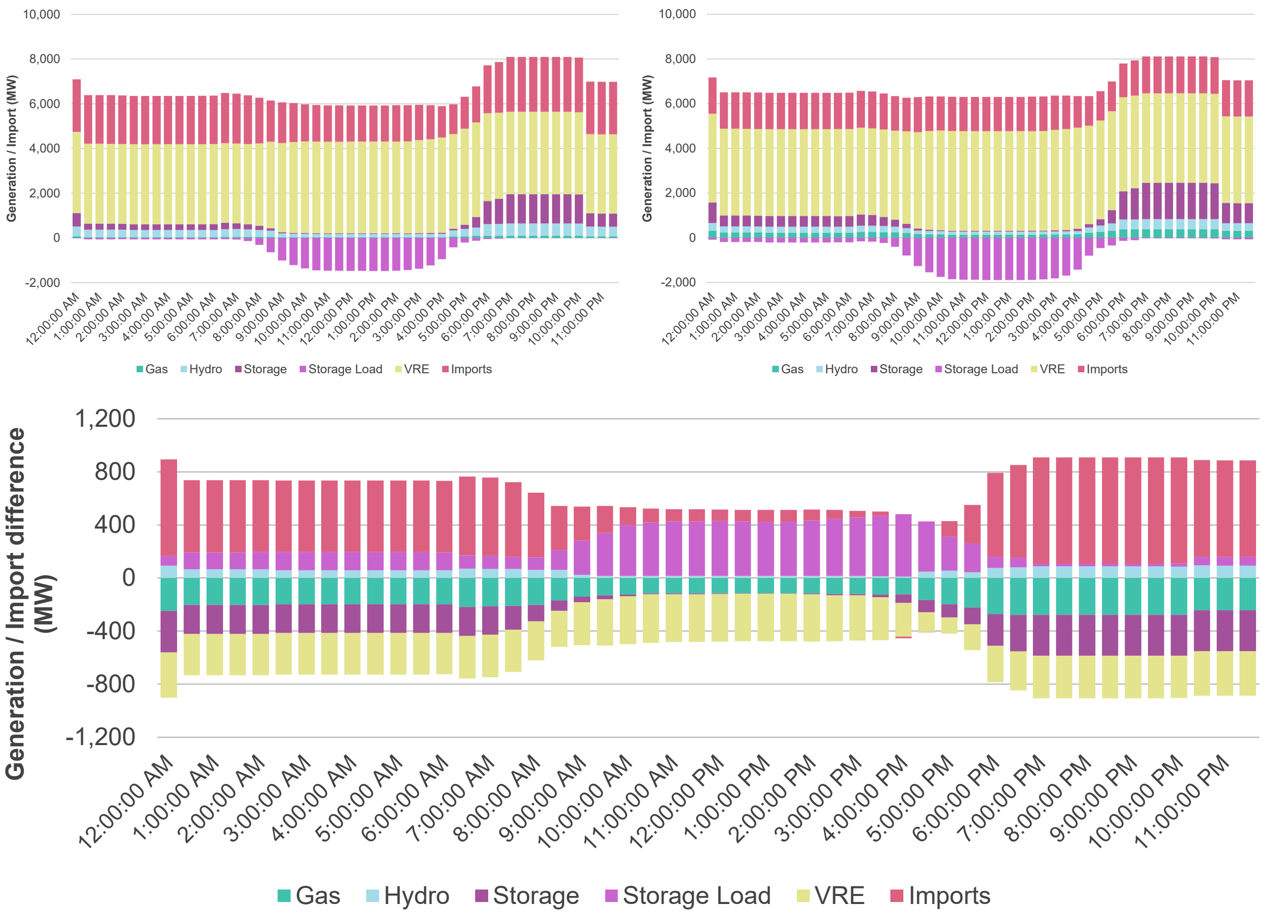


Additional cost savings arise due to reductions in REZ augmentation costs, as VNI West provides additional capacity for the Murray River and Western Victoria REZs. Without VNI West, some additional augmentations to these REZs, as well as others in the NEM, are required.

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-fired 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 A6.8.1.

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*



The net market benefits of VNI West in *Step Change* are summarised in Table 28, 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 28 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. In general, HumeLink delivers positive net market benefits from the time at which the fourth New South Wales coal-fired power station (including Liddell and Eraring) retires. Over this period, HumeLink provides greater access to Snowy 2.0 and other southern New South Wales and Victorian-imported generation to consumers in metropolitan areas of New South Wales, 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 *Step Change* 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-fired generation. The benefits provided by HumeLink in *Step Change* are summarised in Table 29, 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*

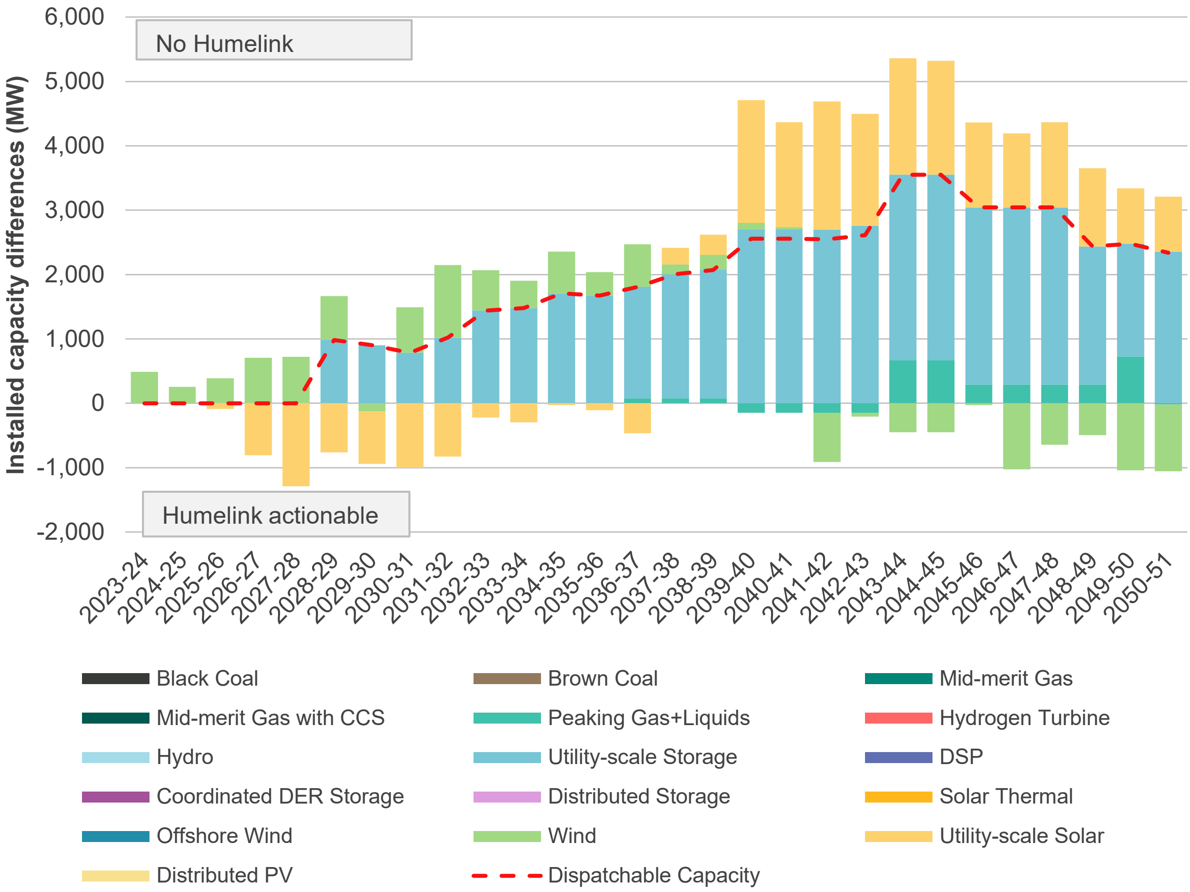


Table 29 Net market benefits of HumeLink in *Step Change*

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 *Progressive Change* that assumes the fourth New South Wales coal station is retired by 2027-28. The results (see Table 30) 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 *Progressive Change*) change from being negative to positive. This clearly demonstrates the resilience to accelerated coal retirements HumeLink provides.

Table 30 Net market benefits of an actionable HumeLink with early black coal retirement (CDP8 vs CDP2)

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

The benefits of HumeLink are explored in further detail, including considering the impact of updated input assumptions, in Section A6.7.3.

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

Table 31 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 31 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%

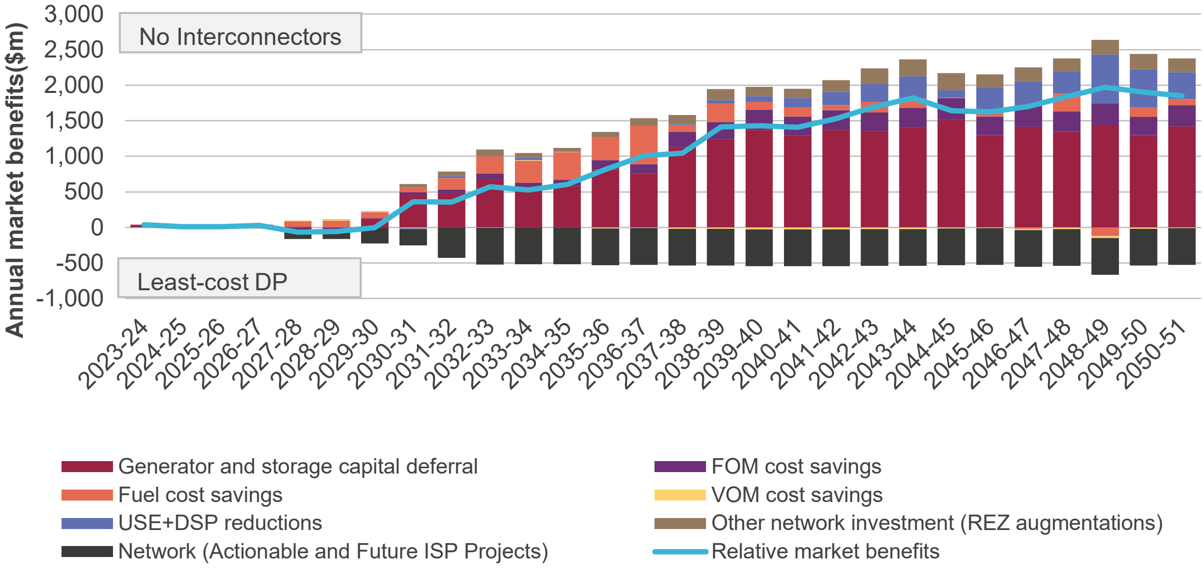
Based on these outcomes, it is evident that:

- 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, meaning that the majority of benefits arise from developing transmission within regions to unlock REZ.

Figure 19 below highlights the need for interconnector investment, comparing the outcomes of CDP10 against the DP without VNI West, Marinus Link and QNI Connect at any stage, for *Step Change*. 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 A6.6.2 ($4.6 billion for Marinus Link and $1.9 billion for VNI West) and QNI Connect ($1.3 billion, see Section A6.8.7), which totals $7.8 billion.

Figure 19 Demonstrating the market benefits of interconnector augmentations



A6.7 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 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 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 except 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 32, based on outcomes of modelling for the Draft ISP.

Table 32 Comparing net market benefits in CDP1 and CDP7 ($ billion) – New England REZ Transmission Link

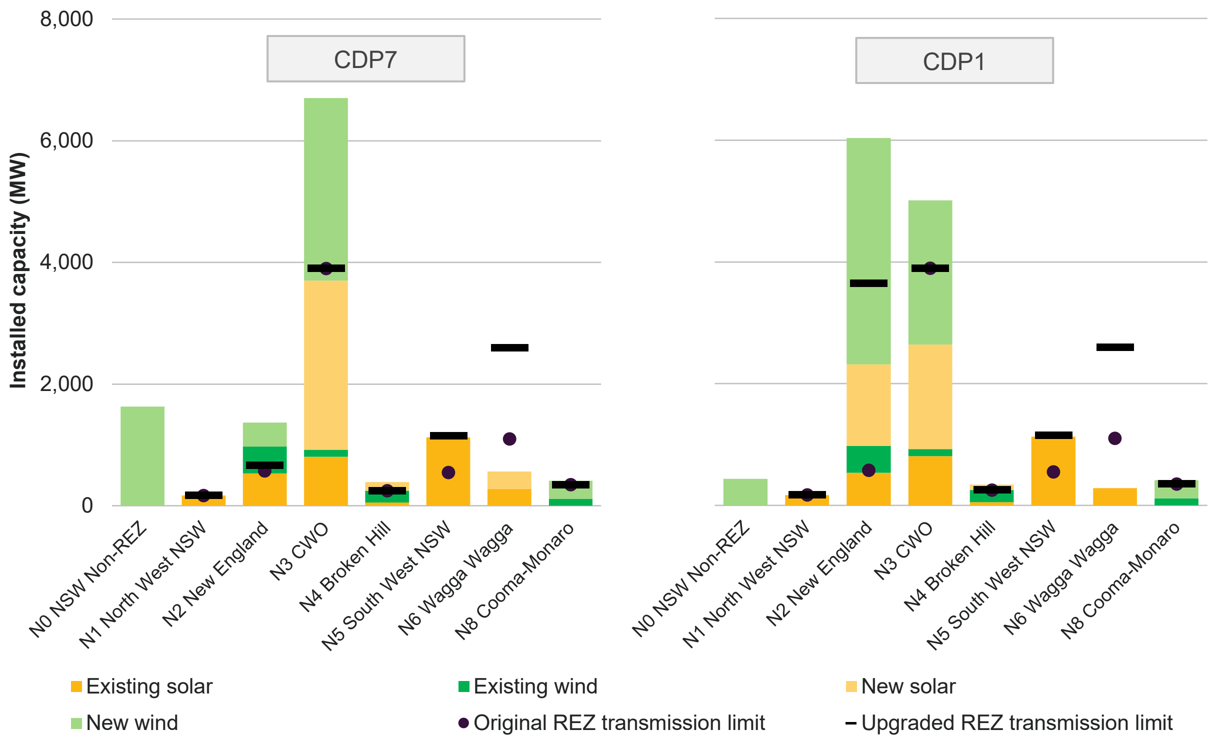
Scenario	CDP1 – with New England REZ Transmission Link actionable	CDP7 – without New England REZ Transmission Link actionable	Regret of “waiting and seeing”, rather than acting now
Step Change	25.50	25.49	0.01
Progressive Change	16.72	16.67	0.04
Hydrogen Superpower	68.95	68.45	0.49
Slow Change	4.17	3.94	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 *Step Change*. 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[17], 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.

[17] 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.

Figure 20 Comparison of New South Wales VRE development by 2028-29 – CDP7 vs CDP1, *Step Change*



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 New South Wales 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 project 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 *Slow Change*, increased supply to Sydney is beneficial 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-fired 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.

The comparison, shown in Table 33, shows regrets associated with delaying the augmentation beyond its actionable in three of the four scenarios, and on a scenario-weighted basis. This analysis is based on Draft ISP modelling.

Table 33 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 34 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 34 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[18] development in New South Wales to be located within Sydney in *Progressive Change*. As shown in Table 35, even considering this forced storage development, an early reinforcement of the Sydney Ring continues to deliver additional net market benefits.

Table 35 Sensitivity testing the impact of storage development concentrated in the Sydney area in *Progressive Change*

	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

[18] Described in the Infrastructure investment objectives in the New South Wales Electricity Infrastructure Investment Act, available at https://legislation.nsw.gov.au/view/pdf/asmade/act-2020-44.

A6.7.1 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 *Step Change* and *Hydrogen Superpower* have an optimal timing of the first cable of Marinus Link that requires the project to be progressed as actionable. As this section is based on Draft ISP analysis, that actionable timing is assumed to be 2027-28; the subsequent subsection details the impact of updated inputs and assumptions including the two-year delay in the Marinus Link EISD.

A comparison of CDP2 and CDP6 provides the ability to explore the risks of over- and under-investment associated with an actionable Marinus Link. Although discussing Draft 2022 ISP results, this has been changed from the comparison published in this appendix in the Draft ISP (previously CDP1 with CDP5).

This means that the comparison now includes an actionable VNI West in both CDPs. Results are robust to this change (with no change in weighted net market benefits) but this comparison is more appropriate given that *Step Change* and *Hydrogen Superpower* (which make up 67% of the weighting) both have an actionable VNI West timing as part of their optimal development paths.

Table 36 shows that an actionable Marinus Link delivers additional net market benefits in *Step Change* and *Hydrogen Superpower*, but not in *Progressive Change* and *Slow Change*.

Table 36 Comparing net market benefits in CDP2 and CDP6 ($ billion) – Marinus Link

Scenario	CDP6 – Without ML actionable	CDP2 – With ML actionable	Regrets of "waiting and seeing" rather than acting now
Step Change	25.59	25.59	0.01
Progressive Change	16.47	16.26	-0.21
Hydrogen Superpower	69.37	70.01	0.65
Slow Change	3.62	3.25	-0.37
Weighted Net Market Benefits	29.51	29.54	0.04

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

Table 37 compares the benefits provided by an early Marinus Link development between *Progressive Change* and *Step Change*. The key differences are:

- Gross market benefits are higher in *Step Change* 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 *Step Change* means that these benefits are realised earlier than in *Progressive Change*.
- The additional transmission costs in *Step Change* are lower in NPV terms as the optimal deferred timing of Marinus Link (Cable 2) (2031-32) is one year earlier than in *Progressive Change* (2032-33).

Table 37 Comparing the impact of an actionable Marinus Link timing between *Progressive Change* and *Step Change*

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	110	14
FOM cost savings	-5	-24
Fuel cost savings	91	83
VOM cost savings	10	4
USE+DSP reductions	-7	0
Other Network investment (REZ augmentations)	-17	1
Gross market benefits	182	79
Network (Actionable and Future ISP Projects)	-174	-288
Total net market benefits	8	-208

The extract from Table 20 presented in Table 38 shows that in comparison to CDP6, CDP2 (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 39, and shows that the larger regret in *Hydrogen Superpower* is driving the higher ranking of CDP6 under the LWWR approach, despite the relatively low scenario weighting of the scenario. In *Hydrogen Superpower*, 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 38 Comparing CDP2 and CDP6 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
6 – wait and see	25.59	16.47	69.37	3.62	29.51	5	0.20	5
2 – progress now	25.59	16.26	70.01	3.25	29.54	3	0.13	2
Benefit of actionable ML	0.01	-0.21	0.65	-0.37	0.04	-	-	-

Table 39 Comparing the weighted regret of CDP2 and CDP6 ($ million)

CDP Number	*Step Change*	*Progressive Change*	*Hydrogen Superpower*	*Slow Change*	Worst Weighted Regret
Regret: CDP6 – wait and see	8	249	1164	718	-
Weighted Regret: CDP6	4	72	198	29	198
Regret: CDP2 – progress now	0	457	519	1088	-
Weighted Regret: CDP2	0	133	88	44	133

Impact of updated assumptions for Marinus Link

This section details the impact of the updated input assumptions since the Draft ISP on Marinus Link, including the delayed EISD that was flagged in the Draft ISP but not able to be included in the Draft ISP modelling. An analysis of the impact of this change in isolation was provided in Section A6.6.1 of the Draft ISP.

Table 40 presents the benefits of an actionable timing of Marinus Link, in *Step Change* using updated inputs. The most recent cost information provided to AEMO increased the project's cost for the two Marinus Link cables. The impact of this cost increase has been considered in the final row of the table.

Table 40 Impact of delayed Marinus Link actionable timing earlier versus later in *Step Change* (NPV, $ million)

	Step Change
Draft ISP assumptions (Comparing Marinus Link 2027-28 actionable timing to 2029-30 timing)	8
Updated inputs (Comparing Marinus Link 2029-30 actionable timing to 2031-32 timing)	86
Updated inputs + most recent cost information (Comparing Marinus Link 2029-30 actionable timing to 2031-32 timing)	69

In the Draft ISP, there was a relatively minor net benefit from an actionable timing for Marinus Link. As a result of the change in the later Marinus Link EISD, the cost of delaying Marinus Link a further two years beyond the actionable timing now incurs a larger cost of $86 million in net market benefits in *Step Change*. This is largely due to the Marinus Link delay resulting in more immediate additional costs from further investment requirements in large-scale storage and wind capacity.

This analysis reaffirms findings from the Draft ISP that tested the impact of a two-year delay in the Marinus Link EISD (2027-28 in the Draft ISP) on the benefits of an actionable Marinus Link. This analysis also concluded that when the EISD is delayed, the cost of not proceeding with an actionable Marinus Link is much greater compared to the earlier EISD assumption of the Draft ISP.

The increase in cost has resulted in a narrowing of the net market benefits of a 2029-30 actionable Marinus Link, however the earlier timing still provides $69 million greater benefits relative to a delayed Marinus Link and would therefore remain preferred at an actionable timing.

Considering the most recent cost information on the TOOT analysis reduces the NMB of Marinus Link from $4.5 billion to $4.4 billion. The reduction in TOOT net market benefit, $115 million, is not equivalent to absolute increase in costs of the most recent cost information, due to the impact of annualising the cost within the modelling horizon, and the discounting back to 2021 dollars.

A6.7.2 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 *Step Change* and *Hydrogen Superpower*, it is optimal at an actionable timing (2031-32 and 2030-31 respectively). However, the optimal timing is delayed considerably in both *Progressive Change* and *Slow Change*.

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

Step Change and *Hydrogen Superpower*, but brought forward in *Progressive Change* and *Slow Change*. 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 Table 41, along with their ranking under the two ranking methodologies. This analysis is based on Draft ISP outcomes.

Table 41 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 an actionable timeframe) results in a higher ranking under both CBA approaches. Table 42 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 42 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 need to progress 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. This section is based on analysis from the Draft ISP, and as such assumes that both Marinus Link cables are operational before VNI West is commissioned (as a result of the CDPs being compared). The first cable is operational from 2027-28, while the timing of the second cable varies by scenario (2029-30 in *Step Change* and *Hydrogen Superpower*; and a year later in *Progressive Change* and *Slow Change*).

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 43.

Table 43 Comparing the net market benefits of progressing VNI West now, with versus 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 *Progressive Change*. 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 44. This analysis is based on Draft ISP results.

Table 44 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 45, which shows that when combined, these additional benefits are immaterial. This analysis is based on Draft ISP results.

Table 45 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 *Hydrogen Superpower* and *Slow Change* 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 withdraw capacity – it is no longer such a profit-maximising strategy in the competition benefits modelling. 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 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 preferred in *Progressive Change* and *Slow Change*). It is assumed that staging does not result in additional costs in scenarios where stage 2 (commissioning) follows immediately from stage 1 (early works).

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 *Step Change* and *Hydrogen Superpower*, 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 *Progressive Change* and *Slow Change*, the risk to consumers of over-investment is minimised by committing to a smaller investment of which the majority of value 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 been spent. 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, the expiry of land options and environmental impact assessments, or the need to repeat detailed engineering design as the power system changes).

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 Table 46, and are based on modelling from the Draft ISP.

Table 46 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 *Progressive Change* and *Slow Change*.

Table 47 presents the regrets by scenario and worst weighted regrets for the three CDPs (also based on Draft ISP modelling). As already seen in Table 42 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 47 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 43) and additional resilience to early coal retirements (demonstrated by Table 44) would further improve the value of a staged VNI West.

A6.7.3 Assessing the benefits provided by HumeLink

The Draft ISP found that the optimal timing of HumeLink is strongly linked to coal closures, particularly in New South Wales. As such, scenarios with a faster transition towards net zero emissions result in an earlier optimal timing for HumeLink.

The Draft ISP also ultimately proposed CDP12 as the ODP, ranked second based on weighted net market benefits and third on LWWR – at an additional cost of $20 million over a delayed HumeLink timing. However, if the schedule slipped leading to a two-year delay in project delivery, CDP12 ranked highest on the basis of weighted net market benefits, with considerable regret to not proceed with early works on HumeLink. The likelihood of slippage needed to be as low as 10% for CDP12 to become the highest ranked CDP.

This section re-examines the cost and benefits of a staged HumeLink using updated inputs and reviews the impact of slippage and further coal retirements on the following CDPs:

- CDP10 (HumeLink at delayed timing).
- CDP11 (HumeLink at earlier actionable timing).
- CDP12 (HumeLink with a staged timing).

Consideration of reliability benefits and (indicative) competition 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. The Draft ISP AEMO assessed CDP10 and CDP11 in more detail using time-sequential modelling in *Progressive Change* and *Step Change*.

This modelling quantified the potential competition cost savings and any additional reliability benefits that were not captured using the capacity outlook model. The competition and reliability benefits calculated by this assessment are provided in Table 48, with minor reductions to the reliability benefits in *Progressive Change* (compared to the Draft ISP) to account for the change in the timing of HumeLink in CDPs where it is not at the earliest possible timing.

Table 48 Additional market benefits for progressing HumeLink as soon as possible ($ million)

	Step Change	*Progressive Change*	Weighted
Reliability Benefits	8	46	17
Competition Benefits (indicative only)	64	216	95

Draft ISP analysis found that HumeLink delivered 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. These competition benefits are provided here for indicative purposes only and are not used in any subsequent analysis in this Appendix or in the 2022 ISP.

In *Progressive Change*, the Draft ISP analysis found that HumeLink provides material additional reliability benefits that were underestimated by the capacity outlook model. These additional reliability benefits were not included in the wider cost benefit analysis to this point but are included in the subsequent analysis in this section which focuses on the benefits of HumeLink.

Costs and benefits of an actionable HumeLink timing across the scenarios

The optimal timing of HumeLink continues to be strongly linked to coal closures under updated inputs. With the earlier retirement of Bayswater Power Station in *Progressive Change,* the optimal timing of HumeLink is brought forward two years (to 2033-34) compared to the Draft ISP in that scenario. The optimal timing is also brought forward in *Slow Change*.

Table 49 presents the regret (reduction in net market benefits compared to a delayed HumeLink, the top ranked CDP10) associated with an actionable HumeLink (CDP11) with updated inputs. This table shows that the weighted regret of a fully actionable HumeLink (without explicit project staging) has reduced by $71 million to $189 million compared to the Draft ISP. This is the result of lower levels of regret associated with an actionable HumeLink under updated inputs in all scenarios except *Hydrogen Superpower*.

Table 49 Regret associated with an actionable HumeLink modelled following input changes ($ million)

		*Step Change**	*Progressive Change**	*Hydrogen Superpower*	*Slow Change*	Weighted
Regret of actionable HumeLink	**Draft ISP assumptions**	192	616	-184	394	260
	Updated inputs	175	434	-202	248	189

* Includes additional reliability benefits in both the Draft ISP modelling and with updated inputs.

Considering the benefits of a staged delivery of HumeLink

Updated modelling confirms that HumeLink is optimal at the earliest timing in *Hydrogen Superpower*, and shortly thereafter in *Step Change*. As a result, AEMO continues to consider 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 flexibility in this timing if circumstances change maximises benefits to consumers.

The regret associated with a staged HumeLink is now just $3 million (down from approximately $20 million in the Draft ISP) compared to a delayed HumeLink. This is driven by the lower cost of early works in *Progressive Change* and *Slow Change* (due to an earlier optimal timing for HumeLink), and greater benefit in *Hydrogen Superpower* associated with an actionable timing of HumeLink.

Table 50 Regret associated with a staged HumeLink modelled with new input changes ($million)

		Step Change	*Progressive Change*	*Hydrogen Superpower*	*Slow Change*	Weighted
Regret of staged HumeLink	**Draft ISP assumptions**	0	149	-184	166	19
	Updated inputs	0	130	-202	0[19]	3

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

The remainder of this section is based on updated inputs for the preparation of the final ISP.

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 delayed if it becomes evident that a later delivery timing would increase benefits to consumers at the next appropriate decision gateway. It also provides opportunities to reduce uncertainty around cost estimates and ideally bring the project costs down.

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

- Minimises regret in *Hydrogen Superpower* 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 *Step Change*.
- Minimises the risk to consumers of over-investment to deliver to a timetable that is not necessary under *Progressive Change*. The staging of early 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 a later than optimal delivery, should the project completion slip in *Step Change*.

In January 2022, AEMO completed the ISP feedback loop which confirmed the early works for HumeLink remains aligned with the ISP's ODP. Further details on the scope of early works are provided in Section 5.4 of the ISP.

Considering the risk of schedule slippage

Table 51 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 51 Assessing the benefits of HumeLink as a staged actionable project, including consideration of schedule slippage under updated inputs

Scenario	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	24.48	24.48	24.30	24.48	24.44	24.49
Progressive Change	15.10	15.23	14.79	15.10	15.23	15.02
Hydrogen Superpower	64.59	64.38	64.59	64.38	63.75	64.38
Slow Change	3.53	3.53	3.28	3.53	3.46	3.53
Weighted	27.74	27.74	27.55	27.70	27.61	27.68

The table above includes $130 million of early works cost in *Progressive Change,* but assumes that simply slowing down the construction timeline in *Step Change* comes at no additional cost to consumers. The included cost of early works is lower than the reported $330 million total 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, in addition to the later cost of rework. This table also includes additional reliability benefits for CDP11 in *Progressive Change* and *Step Change* (see Table 48).

Assuming no schedule slippage, CDP12 ranks second on the basis of weighted net market, only marginally less beneficial than the highest ranked CDP10[20]. This marginal additional insurance cost of just $3 million provides flexibility to respond to accelerated decarbonisation ambitions or coal retirements, as well as managing the risk of extended project delays. As shown above, 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 associated with CDP10 (delayed HumeLink) and with not proceeding with early works in *Hydrogen Superpower*, and to a lesser extent in *Step Change.*

There would only need to be a 4% chance (down from the 10% estimate found in the Draft ISP) of schedule slippage resulting in a two-year delay for the staged actionable project to optimise benefits for consumers.

Staged project provides increased resilience to early coal closures

A further sensitivity was simulated that explored the impact of earlier coal closures in New South Wales in both *Progressive Change* and *Step Change.* In this sensitivity, an additional 2,740 MW of coal capacity is assumed to be retired from 2026-27. Table 52 shows that when this occurs, CDP12 delivers the greatest net market benefits, further demonstrating that a staged project targeting delivery by 2026-27 helps mitigate against this risk.

Table 52 Assessing the benefits of HumeLink as a staged actionable project, including consideration of early coal retirements under updated inputs

Scenario	Net market benefits ($ billion)					
	No early coal closures			Early coal closures in *Step Change* and *Progressive Change*		
	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 for delivery in 2026-27 (CD12)	No action, delivery from 2028-29 (CDP10)	Full project progressed now, delivery in 2026-27 (CDP11)
Step Change	24.48	24.48	24.30*	23.72	23.53	23.72*
Progressive Change	15.10	15.23	14.79*	14.33	13.27	14.33*
Hydrogen Superpower	64.59	64.38	64.59	64.59	64.38	64.59
Slow Change	3.53	3.53	3.28	3.53	3.53	3.28
Weighted	27.74	27.74	27.55	27.14	26.70	27.13

* Includes additional reliability benefits for CDP11.

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

There only needs to be a 1% likelihood of early coal closures for the probability-weighted net market benefits of a staged HumeLink to be greater than a delayed HumeLink, and therefore for CDP12 to optimise benefits for consumers over CDP10.

A6.7.4 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 *Hydrogen Superpower* compared to other scenarios 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, *Hydrogen Superpower* 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 such an early retirement of the power station, and as such no benefit to this actionable timing, as shown in Table 53. This table compares CDP3 with CDP8, which share all the same actionable projects except that CDP8 does not feature an actionable Gladstone Grid Reinforcement. This analysis is based on the outcomes of the Draft ISP modelling.

Table 53 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, *Hydrogen Superpower* 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 *Slow Change* as this reinforcement is never needed given the assumed retirement of local industrial facilities, offsetting the decline in local generation.

On balance, this comparison suggests 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 project to be completed at or before the retirement of Gladstone Power Station, particularly if local industrial loads are expected to continue operating beyond the power station’s closure. 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, noting that this project does not materially impact any of the other ISP projects considered in this ISP.

A6.7.5 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 an expanded analysis consistent with the Draft ISP. In general, all of the projects that are actionable in the 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 ODP. 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*[21], and are also provided in Table 5 of the 2022 ISP. 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 A6.6.2, the overall benefits of New England augmentations are significant. Under *Step Change*, 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"). This section is based on Draft ISP modelling.

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 54, 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 market benefit of $113 million. Applying a 50% cost increase, the augmentation is no longer found to be preferred at an actionable timing in *Step Change* and in *Progressive Change*. There are also reductions in benefits in *Hydrogen Superpower* and *Slow Change*. The weighted net market benefits of an actionable timing are still marginally positive given how beneficial it is in *Hydrogen Superpower*, where the augmentation also helps facilitate interconnector flows between Queensland and New South Wales.

Table 54 Net market benefits ($ million) of progressing New England REZ Transmission 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	14	43	494	236	113
With 50% cost increase	-95	-45	406	148	15

Sydney Ring

The Sydney Ring was demonstrated in Section A6.6.2 to deliver net market benefits of $3.4 billion when compared to a TOOT development path without the project. This section is based on Draft ISP modelling.

[21] At https://aemo.com.au/-/media/files/major-publications/isp/2021/transmission-cost-report.pdf.

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 55 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, *Step Change*, *Progressive Change* and *Hydrogen Superpower* 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 *Slow Change* is substantial. However, weighted across the scenarios, weighted net market benefits remain positive for the actionable timing.

Table 55 Net market benefits ($ million) of progressing Sydney Ring 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	88	221	214	-168	138
With 50% cost increase	47	181	174	-474	86

Marinus Link

Table 56 shows the impact of applying a 20% cost increase (to both Marinus Link cables) when comparing an actionable timing to a delayed timing (as opposed to comparing against never having either Marinus Link cable). This analysis has been updated since the Draft ISP to account for the later EISD, as well as the other input assumption updates, though not the latest cost increase supplied by Tas Networks.

Even applying a 20% cost uplift, the actionable timing still delivers positive net market benefits in *Step Change,* and weighted across all scenarios. Given that the cost increase supplied by Tas Networks sits well within this range, this further reinforces that an actionable Marinus Link timing is preferred.

Table 56 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	86	68	463	-98	138
With 20% cost increase	29	11	406	-145	81

VNI West

Section A6.6.2 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 *Step Change*, 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 A6.7.2 explored the value of project staging in providing the flexibility to deliver VNI West at a beneficial timing.

Table 57 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. This analysis has been updated since the Draft ISP.

VNI West continues to deliver positive net market benefits in *Step Change* under a 10% cost increase, though not under a larger 30% cost increase. In *Hydrogen Superpower* VNI West remains beneficial at an actionable timing even when applying a 30% cost increase. In *Progressive Change* and *Slow Change*, an actionable VNI West if applying these higher costs would further decrease net market benefits.

On a scenario weighted basis, an actionable VNI West still continues to deliver positive weighted net market benefits under a 10% cost increase, although with a 30% cost increase it would no longer provide a positive net market benefit to proceed under an actionable timeframe.

Table 57 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	26	-199	643	-458	46
With 10% cost increase	14	-266	619	-541	14
With 30% cost increase	-8	-401	573	-706	-51

If there was 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 A6.7.3, 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 *Step Change* and *Progressive Change* respectively, and HumeLink was beneficial in all scenarios. However, as detailed in Section A6.7.3, 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 58 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. This analysis has been updated since the Draft ISP.

Table 58 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	-175	-434	202	-248	-189
With 30% cost increase	-319	-733	105	-607	-378

* Includes additional reliability benefits

A6.8 Testing the resilience of the candidate development paths

A6.8.1 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 *Progressive Change* and *Step Change*, which together account for the majority of the scenario weighting. This sensitivity was conducted on Draft ISP inputs.

For this sensitivity analysis, a selection of CDPs were re-modelled to explore the impact of a lower gas price on some of the strategic 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 helps understand how robust the top ranked CDPs are to sustained 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 59, a lower long-term 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-fired 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 59 Net market benefits by CDP and scenario in the base case and low gas price sensitivity (net market benefits, $ billion)

CDP	Base assumptions				*Low Gas Price*			
	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 *Slow Change* and *Hydrogen Superpower* 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 59 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 *Progressive Change*, fuel cost savings that are due to reductions in gas-fired generation are minimal. In *Step Change*, there are some cost savings that are due to reductions in gas-fired generation, however the difference in gas prices between the base case and low gas price sensitivity are more minimal for *Step Change*.

Impact of low gas prices on VNI West timing

Table 60 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 *Progressive Change* where the impact equates to a 15% reduction in gross benefits. Impacts in *Step Change* are minimal given the smaller difference in gas prices and because the non-actionable timing is only one year after the actionable timing.

Table 60 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 59, 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 61, sustained 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 million and $19 million in *Progressive Change* and *Step Change* 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 *Progressive Change*, HumeLink does deliver material fuel cost savings attributable to reductions in gas-fired generation. In the low gas price sensitivity, there is an increase in gas-fired generation generally, as well as additional investment in peaking gas-fired generators in favour of utility-scale storage. In the sensitivity, HumeLink results in greater reductions in gas-fired 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 *Step Change*, 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 61 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.

A6.8.2 Sensitivity to the discount rate

AEMO has included three 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.
- Decreasing the discount rate to 2% on a selection of key CDPs.

These sensitivities were conducted on Draft ISP inputs.

Applying a 10% discount rate

Table 62 presents the performance of each CDP (that features Marinus Link[22]) 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 63 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.

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

Table 62 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

Table 63 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 only one of the projects 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 *Hydrogen Superpower*, 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 without staging, 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 64 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 64 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 [as calculated in the

Draft ISP]) for the impact of a staged HumeLink on net market benefits to be neutral when applying a 7.5% discount rate.

Applying a 2% discount rate

A sensitivity analysis was undertaken to explore the impact of a 2% discount rate on the ranking of a selection of CDPs. Table 65 shows the performance of the low discount rate and their changes in the CDP ranking. Rankings are all relative to the subset of CDPs modelled.

Table 65 Comparison of CDP rankings – 2% discount rate sensitivity and base

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

The key insights from the low discount rate analysis are:

- CDP12 that has a staged delivery of HumeLink and VNI West is now the highest ranked on a weighted net market benefit basis, with weighted net market benefits of $84 million higher than the second highest CDP10 that does not have early works on HumeLink (and including staging for VNI West).
- CDP8 has risen in the rankings. This CDP removes staging on HumeLink and VNI West, and demonstrates that a lower discount rate favours more accelerated transmission development.

A6.8.3 Sensitivity to higher DER uptake

AEMO has also explored a sensitivity on *Step Change* that considers the impact of higher DER uptake, informed by the latest forecast from the Clean Energy Regulator (CER)[23]. In this sensitivity, distributed PV uptake was adjusted by the factors presented in Table 66, 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). This sensitivity was conducted on Draft ISP inputs.

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%.

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

Table 66 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 67 presents the impact of the DER adjustment in *Step Change*, and its impact on the ranking of CDPs[24] 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 67 CDP performance under the Base DER and high DER sensitivity (net market benefits, $ 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

A6.8.4 Sensitivity to lower distributed storage and less coordination

AEMO received several submissions to the Draft 2022 ISP suggesting that the Draft ISP's projections of DER were too high, particularly the uptake of distributed storage. The level of co-ordination was also questioned, given the required policy reforms, social licence issues, and issues associated with managing the interface between transmission and distribution networks, with some stakeholders concluding that further investigation may be required. In response to this feedback, AEMO has included an additional sensitivity which tests the impact of applying the lower level of uptake and coordination from *Progressive Change* in *Step Change*. This sensitivity was conducted on Draft ISP inputs.

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

For this sensitivity analysis, a selection of CDPs were re-modelled and compared to explore the impact of lower distributed storage uptake and coordination in *Step Change* on the ranking of CDPs. As can be seen from Table 68 there are no changes to the rankings of CDPs with this reduction in distributed storage, indicating the results are robust to this assumption.

Table 68 CDP performance under the Base and Lower Distributed Storage sensitivity (net market benefits, $ billion)

CDP number	Base		*Lower Distributed Storage*	
	Step Change	NMB rank	*Step Change*	NMB rank
1	$25,500	6	$25,462	6
2	$25,594	1	$25,552	1
5	$25,510	5	$25,482	5
6	$25,586	4	$25,545	4
8	$25,393	7	$25,353	7
9	$25,278	9	$25,201	9
10	$25,594	1	$25,552	1
11	$25,393	7	$25,353	7
12	$25,594	1	$25,552	1

A6.8.5 Sensitivity to offshore wind investment

In response to the Victorian Government's Offshore Wind Policy Directions Paper released in March 2022[25], AEMO has conducted an offshore wind sensitivity, informed by the offshore wind targets stated in the Policy Directions Paper. This sensitivity applied a constraint to develop the targets within the Directions Paper to Victorian OWZs (see Table 69). AEMO also included an additional OWZ offshore off the Portland Coast in western Victoria, considering new information on investor interest in areas outside of the Gippsland OWZ which was the sole Victorian OWZ included in the Draft ISP.

AEMO assumed a linear projection for the offshore wind capacity during interim years starting from 2028-29 which is when first power would be provided as per the Policy Directions Paper. This sensitivity also included a lower capital cost trajectory for offshore wind based on the *Global NZE post 2050* scenario from CSIRO's Draft 2021-22 GenCost report[26].

Table 69 Victorian Offshore Wind Targets (MW)

	2032-33	2035-36	2040-41 onwards
VIC	2,000	4,000	9,000

For this sensitivity analysis, a selection of CDPs were re-modelled and compared to explore the impact of offshore wind investment on some of the strategic projects (Marinus Link, VNI West and HumeLink). This analysis was for *Step Change* and was conducted against Draft ISP inputs.

[25] See https://www.energy.vic.gov.au/__data/assets/pdf_file/0016/561400/Offshore-Wind-Policy-Directions-Paper.pdf.

[26] See https://publications.csiro.au/publications/publication/PIcsiro:EP2021-3374.

Table 70 presents the offshore wind sensitivity's impact on net market benefits and CDP rankings. The net market benefits of all CDPs relative to the counterfactual are comparable to the base outcomes. The CDP rankings are also robust to this sensitivity, particularly CDP2, CDP10 and CDP12 which remain as the highest ranking CDPs for *Step Change*.

Table 70 CDP performance under the Base and Offshore Wind sensitivity (net market benefits, $ million)

CDP number	Base			*Offshore Wind*		
	***Step Change* NMB**	**NMB rank**	**NMB relative to optimal**	***Step Change* NMB**	**NMB rank**	**NMB relative to optimal**
2	$25,594	1	-	$24,931	1	-
5	$25,510	5	-$83	$24,780	5	-$150
6	$25,586	4	-$8	$24,911	4	-$19
8	$25,393	6	-$201	$24,729	6	-$202
9	$25,278	8	-$316	$24,550	8	-$381
10	$25,594	1	-	$24,931	1	-
11	$25,393	6	-$201	$24,729	6	-$202
12	$25,594	1	-	$24,931	1	-

The table above demonstrates that, for each of the strategic, actionable projects, the offshore wind sensitivity provides a relatively small impact to the net market benefits of each relevant CDP:

- For **Marinus Link**, by comparing CDP2 and CDP6 the offshore wind sensitivity demonstrates that the benefits of the interconnector marginally increases, from an $8 million benefit in the least-cost DP (which includes Marinus Link as actionable) under base assumptions, to a $19 million improvement to the alternative CDP6 in this sensitivity.
- For **VNI West**, by comparing CDP2 and CDP5 the offshore wind sensitivity demonstrates that the benefits of the interconnector increase, from an $83 million higher NMB in the least-cost DP (which includes VNI West as actionable) under base assumptions, to a $150 million improvement to the alternative CDP5 in this sensitivity. CDP10, with VNI West staged, remains an equal value (and rank) in this sensitivity to CDP2.
  – The increase in net market benefits is largely due to additional avoided storage with offshore wind in Victoria. The impact of offshore wind relative to onshore resources on the need for firming capacity development is described in Appendix 2.
- For **HumeLink**, by comparing CDP11 and CDP10 the offshore wind sensitivity demonstrates that the benefits of the actionable interconnector (in CDP11) is minimal, with a decrease of net market benefits of only $1 million (comparing the $201 million to $202 million reduced benefit relative to the least-cost DP).

A6.8.6 Comparing *Strong Electrification* to *Hydrogen Superpower*

AEMO has also modelled a *Strong Electrification* sensitivity, as a potential alternative to *Hydrogen Superpower* 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 *Hydrogen Superpower* with the same weighting for the purpose of understanding its impact on CDP rankings[27].

Table 71 below highlights the impact that the inclusion of a strong electrification sensitivity (in lieu of *Hydrogen Superpower*) 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*.

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 *Hydrogen Superpower*. 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-fired generators necessary to achieve the carbon emissions reduction objectives support the value provided by the ISP projects. This sensitivity was conducted on Draft ISP inputs.

Table 71 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

A6.8.7 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 *Progressive Change* and *Step Change*, and was applied to Draft ISP inputs.

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

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

Table 72 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 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 72 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

A6.9 NEM-wide distributional effects

The AER's *CBA Guidelines*[28] require AEMO to identify an ODP that promotes the efficient development of the power system. While this assessment is conducted considering only eligible market benefit classes, the CBA guidelines includes the need to provide transparency of the beneficiaries of the identified benefits of the ODP, through distributional effects reporting.

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

"Distributional effects consider the distribution of costs and market benefits of an optimal development path – that is, who receives the benefits and who pays the costs. This can be useful for considering the equity of how costs and benefits are distributed across the market. CBA is focussed on efficiency and aggregates costs and benefits across individuals/entities without regard to the equity of the distribution of those costs and benefits. As such, CBA cannot resolve equity issues. However, it can draw attention to them through considering distributional effects, and allow policy makers the opportunity to address these through government policy." [29]

For the final ISP, AEMO has assessed distributional effects for a selection of CDPs under *Step Change* and *Progressive Change*. By comparing the costs to consumers that arise from each CDP, AEMO has estimated how consumer bills may change depending on the development path (including the effect on the ISP development opportunities).

In the NEM, transmission charges and wholesale energy costs in 2021-22 make up roughly 8% and 34% respectively of the typical residential electricity bill[30]. The remainder of consumer bills is made up of distribution and metering charges (38%), environmental levies (9%) retailer margins (11%) and GST.

Strengthening the network via inter-regional and intra-regional augmentations will see total transmission charges increase over time as these are regulated assets with costs passed through to consumers. However, these transmission augmentations may also drive reductions in wholesale energy cost and with it the associated charges paid by consumers.

Reduction in wholesale energy costs may be driven by:

- Increased competition – increased number of generators able to bid in their units to be dispatched will likely lower the dispatch pool price.
- Reduced generation cost – with renewable generators having low (or no) fuel costs compared to coal and gas-fired generators.
- Increased resilience to outages – reducing the impact of transmission or generator outages, expensive emergency or reserve resources will be required less often.
- Increased resilience to renewable resource availability – with greater access to geographically and technologically diverse renewable resources, fewer forecast periods of reduced energy availability may reduce unserved energy or extreme high prices.

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

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

[30] AEMC. Residential electricity price trends 2021. Available at https://www.aemc.gov.au/sites/default/files/2021-11/2021_residential_electricity_price_trends_report.pdf.

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

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

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

This assessment focuses on CDP 1 and CDP 11 which feature different commissioning timings for key transmission augmentations, as outlined in Table 73. The comparison between these two CDPs under both scenarios highlights the potential costs and benefits to consumers of delivering these strategic projects to an actionable timetable.

Table 73 Timing of key interconnector augmentations in CDP 1 and CDP 11 in *Step Change* and *Progressive Change*

Projects	*Step Change*		*Progressive Change*	
	CDP1	CDP11	CDP1	CDP11
HumeLink	2028-29	2026-27	2033-34	2026-27
VNI West	2032-33	2031-32	2038-39	2038-39
Marinus Link (Cable 1)	2031-32	2029-30	2031-32	2029-30
Marinus Link (Cable 2)	2033-34	2031-32	2033-34	2031-32

While the CDP comparisons focus on the difference in the timing of these strategic projects, a key component of transmission costs later in the ISP horizon is the REZ augmentations that are developed to connect new renewable energy developments[31]. Like the strategic ISP projects that differ between CDPs, these augmentations are assumed to be regulated assets whose costs are recovered by consumers.

Transmission costs increase over the next decade in all development paths as augmentations are delivered. The transmission costs on a per MWh basis is partially offset by the connection and consumption of newly electrified loads (electrification). When consumers start bearing additional transmission charges associated with network augmentations varies between projects (and development paths), depending on each project's assumed expenditure profile associated with early works, construction, and commissioning costs[32,33].

AEMO's forecast approach to wholesale energy cost is reflective of the transition toward a VRE and storage dominated supply mix with minimal to no fuel cost. The average production cost of energy in the NEM purely based on short-run marginal cost is projected to decline significantly because of this. In reality, how much consumers will end up paying for their energy depends on market reforms and how products such as flexibility/ramping and firming will be traded and remunerated in the future NEM. The extent to which consumers will be willing to participate in the market via demand response will also have a material impact on wholesale energy prices and their own electricity bills, as rewards from market participation could offset some of their other charges.

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

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

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

This section assesses the relative costs and benefit to consumers of either actioning the strategic ISP projects listed in Table 73, or delaying these projects to future projects. In this way, it provides insights into the potential risk asymmetry between over and under-investment.

Figure 21 shows the average year on year differences in wholesale energy (purple bars) and transmission costs (teal bars) between CDP1 and CDP11, suggesting that the potential savings in wholesale energy cost far outweigh the additional cost for actioning an earlier commissioning date for the ISP projects. For example, consumers could face a significant increase in wholesale energy costs if HumeLink was to be delayed by two years under CDP1, demonstrated by the significant cost difference in the first two years shown. Delaying VNI

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

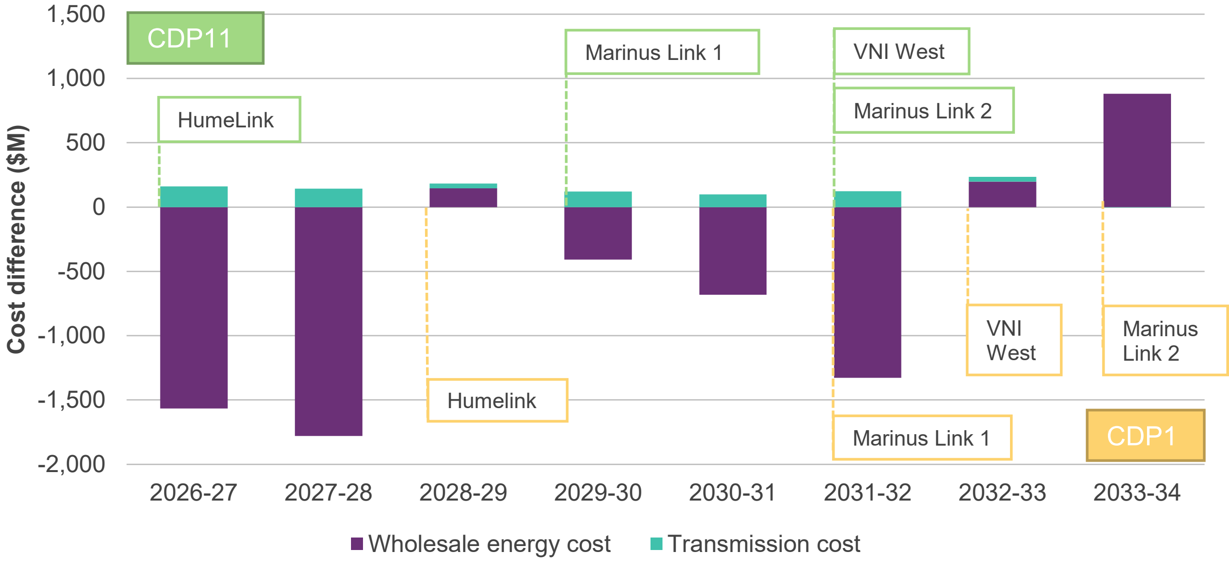
[32] Early works involves the regulatory approval of early investment expenditure in order to firm up cost estimates, and enhance planning prior to final investment decision. The project proponents confirm the approved cost recovery through contingent project applications. In general, AEMO assumes that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

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

West and Marinus Link show a similar impact (although less distinctive, given the overlapping project timings that exist between the CDPs).

Differences in interconnector timing between the two CDPs resolve by 2033-34. In the last two years of the analysis, CDP1 forecast slightly lower wholesale energy cost due to requiring earlier investment in alternative generation developments due to delayed transmission.

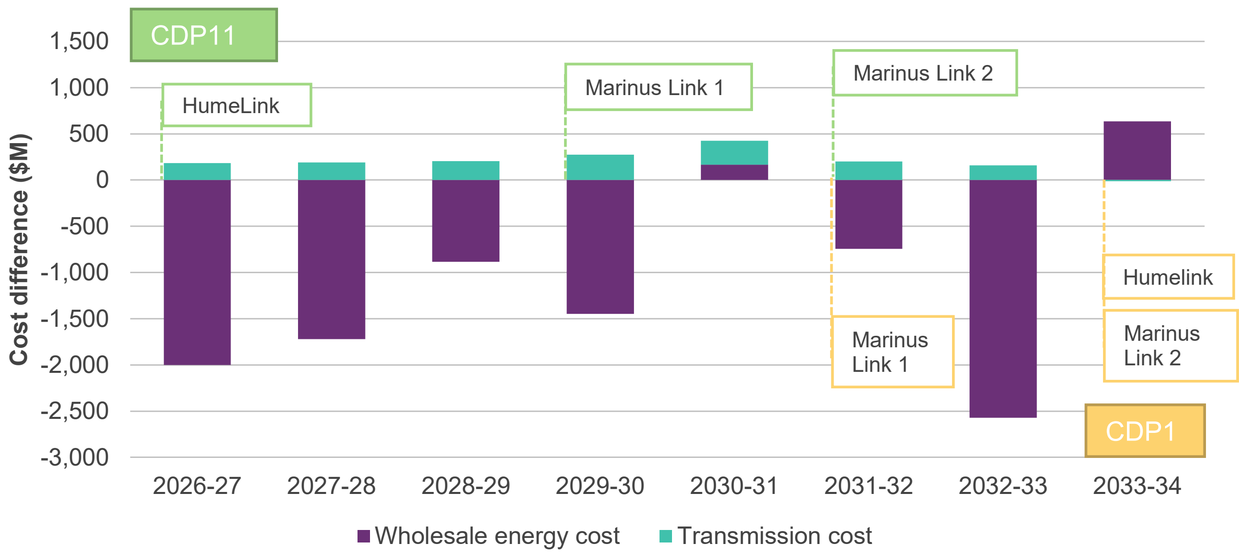
Figure 21 Average year-on-year distributional effects under *Step Change*



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

For *Progressive Change*, as outlined earlier in this appendix, a slower transmission development path is more optimal, for system-wide efficiency. Despite this, Figure 22 shows that consumer wholesale energy costs may be lowered with earlier transmission investments. Under *Progressive Change* the average impact on wholesale energy cost is higher than under *Step Change* due to the wider gap in optimal timing between CDP11 and CDP1 across the modelled horizon.

Figure 22 Average year-on-year distributional effects under *Progressive Change*



In *Progressive Change*, the staged VNI West project would be delayed on completion of early works, protecting consumers from over-investment, and therefore is not shown in the analysis for either CDP. A more detailed assessment of price risks associated with HumeLink can be found in Section A6.9.3.

A6.9.3 Considerations on price risk to consumers

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

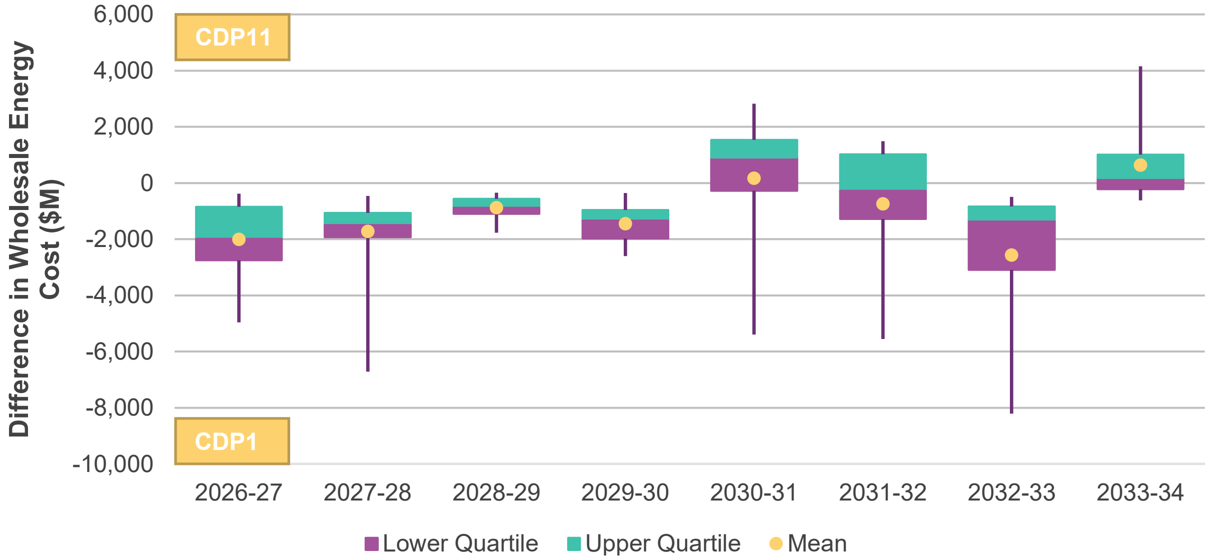
Figure 23 shows the distribution of half hourly differences in wholesale energy costs between CDP1 and CDP11 for *Step Change* presented in the previous section, across different weather conditions and forced outage patterns. Negative differences in costs (CDP11 minus CDP1) indicate that CDP 11 is lower cost than CDP1 and vice versa. It demonstrates that greater price volatility exposure is forecast without timely development of further transmission projects to efficiently share new generation developments.

Figure 23 Distribution of differences in wholesale energy costs under *Step Change*

In some years in the figure, for example 2027-28 and 2031-32 where HumeLink and VNI West respectively are developed in CDP11 but not yet available in CDP1, the magnitude of these cost differences is shown to vary considerably depending on weather and outage patterns and is generally skewed towards higher consumer cost outcomes in CDP1 without the earlier availability of these transmission projects. Coal unavailability for instance, if timed with localised low VRE conditions or high demand, can expose consumers to significant price spikes and increased volatility, as greater reliance on gas-fired generation is needed (at higher operating cost). Transmission developments are shown to reduce this risk by providing accessibility of a geographical diverse pool of low-cost VRE resources. In the absence of earlier transmission development in these years, there is an asymmetric risk of more extreme increases in wholesale costs borne to consumers under adverse weather and outage conditions.

Similar outcomes are projected in *Progressive Change*, as seen in Figure 24. In particular, cost outcomes in the early 2030s in the absence of HumeLink and with the delayed delivery of both Marinus Link cables show significant asymmetric volatility with the possibility of far greater-than-average increases in wholesale costs if weather conditions are unfavourable.

Figure 24 Distribution of differences in wholesale energy costs under *Progressive Change*



Mitigating price risks from transmission construction delays: a HumeLink case study

The optimal timing of a transmission investment depends on a range of factors, such as demand growth, coal retirements and development on new VRE generators. The ISP modelling approach identifies this optimal timing, assuming perfect foresight into when generation capacity will be built or retired, other transmission projects commissioned and the level of demand growth. It also assumes the transmission project is delivered on time.

Section A6.7.3 considered the risk of schedule slippages for HumeLink from the perspective of the cost-benefit analysis. This analysis is expanded in this section to consider the impact on consumer costs. It focuses on HumeLink as the most immediate actionable project, although similar impacts might be observed if other ISP projects were delayed.

In the face of Origin Energy's recent proposal to accelerate the exit of Eraring Power Station and without appropriate and timely investment in replacement generation, wholesale energy prices could increase and become more volatile in the future, potentially exposing consumers to higher cost.

AEMO's analysis demonstrates that timely HumeLink delivery increases resilience and protects consumers from elevated prices. A similar outcome for consumers could be achieved by timely investments in additional generation and storage capacity locally. Both network and non-network solutions are however exposed to risk of schedule slippage which could lead to periods of tight demand supply balance and potentially high prices.

AEMO has examined the impact of a potential delivery delay in 2028-29, the year in which HumeLink was to be delivered in CDP1 (where HumeLink is not an actionable project). The analysis focuses on *Step Change* and considers two cases that involve a delivery schedule slippage in CDP1, and compares these to if it was delivered to its actionable timing in 2026-27 (without schedule slippage):

- **Case 1**: This case considers the risk associated with an unanticipated project delay for HumeLink, not announced to market in time to develop an appropriate alternative generation or storage response to cover for the transmission delay[34].
- **Case 2**: This case considers the lower risk associated with a project delay that has been identified and communicated sufficiently early to enable a generation or storage response. In total, almost 1,500 MW is brought forward across the NEM in response, with 300 MW of renewable generation and 500 MW of large-scale long duration storage in New South Wales[35] .

Should HumeLink be delayed without timely and strong enough signals for additional generation or storage capacity to be brought forward, as in Case 1, New South Wales wholesale prices may increase by up to 26% on average, across a range of weather patterns and generator forced outage conditions. Alternatively, if the market has sufficient forewarning that the project is to be delayed and adequate time for a generation response to be developed, as in Case 2, prices in New South Wales may only rise by 10% (compared to the case with delivery in 2026-27).

The price increase in Case 1, involving no generation and storage response, is due to reduced access to, and therefore lower utilisation of, Snowy 2.0. This leads to a much greater reliance on gas-fired generation and electricity imports from neighbouring regions' firming capacity to meet demand in the mornings and evenings. The more modest price increase in Case 2 is also driven by the limited access and utilisation of Snowy 2.0, but the additional generation and storage capacity in this case leads to additional wind and solar availability throughout the day and greater access to storages to provide supply during peak hours, resulting in a reduced reliance on gas-fired generation and imports (although still greater than in the case with a 2026-27 actionable HumeLink timing).

Figure 25 shows the wholesale cost comparison in New South Wales in 2028-29 between Case 1, Case 2 and the case where HumeLink is constructed to its actionable timing 2026-27. The bars demonstrate that delivering HumeLink on schedule will lead to the lowest total wholesale costs, with prices less frequently at extreme levels. On the other hand, delayed investment of the project, compounded with a schedule slippage and inadequate generation and storage response, may lead to extreme price outcomes. This further demonstrates that the costs to consumers of investing earlier (which may give extra headroom to any schedule slippage) may improve broader benefits. This resilience benefit may also be provided to alternative firming investments, such as energy storage.

[34] AEMO has assumed that timing of retirements under *Step Change* is not impacted by the transmission delay.

[35] Beyond this, the difference narrows in quickly for VRE while some difference in storage remains till 2037-38.

Figure 25 New South Wales wholesale energy cost distribution by price band, delayed HumeLink due to schedule slippages compared to HumeLink delivered to its actionable timing, 2028-29, *Step Change*